135. Drs. Fisher and Horowitz expressed deep concern that—

> PREPA spent the astonishing figure of $165 million in A&G in FY2016, of which $134 million fell into an undescribed discretionary fund. To give this figure context, PREPA spent the equivalent of *more than a third of its entire capital budget* on discretionary A&G spending.[114]

Drs. Fisher and Horowitz recommend a decrease of $17.1 million.[115] The Commission accepts this recommendation. Attachment 1 reflects this recommendation.[116]

Directives

1. PREPA shall decrease A&G labor expense by $17.057 million.

2. PREPA shall develop and submit to the Commission a revised monthly report format, providing for greater detail on PREPA's operational budgets, organized by functional area.

3. PREPA shall provide detailed information on the spending within the "miscellaneous" non-labor segment of the Administrative and General functional area. Such information shall distinguish between funds spent to date and funds not yet spent.

8. Workforce Levels

136. According to PREPA's panel of Miranda, Perez and Sosa, PREPA is having difficulty managing its workforce.[117] They state that PREPA is an inefficient bureaucracy with high absenteeism, has an unacceptable safety record, is overly staffed with non-value-added administrative personnel, especially in the executive directorate, and has an oversized executive team. There is also a shortage of technical expertise. Here is what these witnesses stated:

> Generally, the team encountered outdated human resource processes that were not conducive to a safe and productive workforce. Among the problems were inflexible work rules and high absenteeism. Paid leave was twice the industry norm at 80 days per year. The retirement system is projected to be

[114] Fisher-Horowitz Report at 15 (emphasis in original).

[115] *Id.* at Table 34.

[116] See also Attachment 3 at 6.

[117] PREPA Ex. 3.0 at 31-32. Miranda, who has retired, was a senior executive at PREPA. Perez and Sosa are consultants with Alix Partners.

insolvent by 2024 and needs immediate attention to thwart that result. There also is an unacceptable safety record, with more than 14,000 accidents and 15 fatalities over a 10 year period.

Additionally, PREPA did not have any succession plans with approximately 1,050 staff currently eligible for retirement-many of which are in critical positions. PREPA is currently averaging 350 retirements per year.

PREPA also lacked a formal performance management process and limited use of [Key Performance Indicators] KPIs. The team encountered low accountability and lack of leadership from top management. Often leaders and managers were placed in positions based on political affiliation vs. job qualifications. Job descriptions also were outdated or non-existent.

From an organizational standpoint, PREPA is an inefficient bureaucracy with numerous silos. Certain areas are overly staffed with non-value added administrative personnel. In addition, the executive directorate and executive team is oversized. There also is a shortage of expertise in specific technical skill areas.[118]

Their direct testimony (PREPA Ex. 3.0) describes steps PREPA has been taking to solve these problems. Since 2014, PREPA's headcount has declined by approximately 1,100 full-time employees through attrition. PREPA expects an additional decline of approximately 600 full-time employees by 2019.

137. Reducing headcount does not necessarily increase efficiency. As discussed in Part Two-III, Commission Advisors Fisher and Horowitz concluded that during FY2015 and FY2016 PREPA did not maintain its electric system adequately, in part due to insufficient staff. Within their proposed spending modifications are increases for labor for generation, transmission and distribution, as well as decreases for labor in the A&G area. Specifically, they propose a net increase of $12.068 million for labor, consisting of:

—a $9.680 million increase to Generation Expense;
—a $3.330 million increase to Transmission Expense;
—a $16.115 million increase to Distribution Expense; and
—a $17.057 million decrease to Administrative and General Expense.[119]

We approve these amounts. As indicated, these numbers are within the already approved amounts for generation, transmission, distribution and administrative & general.

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[118] *Id.* at 31.

[119] Fisher-Horowitz Report at Table 34. These adjustments are displayed in Attachment 3 at 6.

9. Energy Administration Assessment

138. PREPA's revenue requirement request includes $5.8 million for the Energy Administration Assessment, established by Article 6.16(c) of Act 57-2014. PREPA is required to pay that amount annually by sending it to the Treasury, which then sends it to the Commission in two installments of $2.9 million each. The Commission approves this amount.

10. Fines and penalties

139. As detailed in the Smith-Dady Report (at 61-62), PREPA has been incurring hundreds of thousands of dollars in fines for environmental non-compliance. Besides the environmental damage, and the awkwardness of government utility violating government rules, there is the problem of financial accountability. PREPA has no shareholders. Therefore, the fines resulting from actions or inactions by executives, managers and employees, fall not on those at-fault individuals but on the ratepayers. Our citizens not only suffer the consequences of environmental damage; they also must pay for the penalties. That is beyond irony. The situation contributes to a culture within PREPA of "not my problem." The purpose of fines and penalties is to induce compliance. Passing the cost on to customers does not achieve compliance.

140. A separate problem is accounting. PREPA says it has been recording its fines and penalties in accounts 92316 and 93000.[120] But the FERC USoA instruction 21-G provides that fines and penalties are to be recorded in account 426.3, Penalties.[121]

141. PREPA stated at the technical hearing that it has received no specific notices of fines or penalties for FY2017.

Directives

1. ***PREPA shall account for fines and penalties in the proper account; specifically, FERC account 426.3.***

2. ***PREPA shall verify that it has not included in its proposed revenue requirement any amounts for fines and penalties.***

3. ***PREPA shall submit to the Commission a full explanation of the causes of fines and penalties from FY2013 to the present, including the names and***

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120 PREPA's 5-digit account numbers appear to correspond with accounts 923 and 930 in the FERC—the standard accounting system used by utilities.

121 "G. Any penalties assessed by the Environmental Protection Agency for the emission of excess pollutants shall be charged to Account 426.3, Penalties."

titles of specific individuals whose actions or inactions contributed to the violations that triggered the penalties.

4. *If PREPA incurs fines and penalties for FY2017 or future years, it shall explain to the Commission the nature of these costs and the specific individuals responsible for the actions or inactions causing the fines or penalties. PREPA also shall submit to the Commission a plan for complying with all rules so as to avoid future fines and penalties.*

5. *PREPA shall continue its policy, per the Consent Decree discussed in its FY2014 audited financial statement, of paying the stipulated penalty in advance to benefit from a 50% discount.*[122]

11. Unused properties

142. PREPA owns properties which it neither uses nor needs to provide utility service.[123] These properties have been recorded on PREPA's books at the cost of acquisition. PREPA is in the process of hiring a real estate management firm to appraise the properties and maximize their value through sale, lease or other use.

Directive relating to unused property

PREPA shall provide updates concerning the appraised value of PREPA's unused property (i.e., property not needed to provide utility service), as well as PREPA's plans for maximizing the value of such properties.

12. Other Directives

1. ***PREPA shall adjust its monthly report format to list monthly and year-to-date actual spending and budgeted values by labor and non-labor expenses in the same functional areas used herein. These reports shall include the total annual budgets and percent of budgets spent in the past month and year-to-date.***

[122] PREPA's FY2014 audited financial statements (PREPA Exs. I-2, pp. 82-101) notes that PREPA has paid fines under the Consent Decree. At page 82 (PFE 000086) PREPA states: "The Consent Decree includes stipulated penalties for certain events of non-compliance. Non-compliance events must be disclosed to the EPA in the corresponding report. Ordinarily, when a cover noncompliance event occurs, the Authority pays the stipulated penalty in advance in order to benefit from a 50% discount of the applicable stipulated penalty."

[123] These properties are listed in PREPA's response to CEPR-RS-05-33.

2. *PREPA shall prepare a report, to be submitted with its next rate case filing, regarding its use (or lack thereof) of the additional $19.4 million of operational expenses allowed by the Commission (per Attachment 3, page 6) and the effect of that spending on its system.*

3. *PREPA shall continue to record its monthly operations spending by directorate. When PREPA reallocates funds between directorates, it shall memorialize and justify such reallocations in written form.*

4. *PREPA shall prepare a report, to be submitted with its next rate case filing, that shall include it's as-approved internal operations expense budget by directorate, its actual monthly operations spending by directorate, and a listing of these memorialized reallocations and the justifications thereof.*

B. Fuel and power purchase expense

143. For fuel and purchased power, PREPA originally proposed a revenue requirement of about $1.47 billion in FY2017: $656 million for fuel and $820 million for purchased power. The $656 million figure results from PREPA's projection of $763.7 million in fuel expense, less performance savings of $107.7 million.[124] Combined, these amounts total approximately half of PREPA's entire FY2017 revenue requirement. These figures are projections, not budgets, because there will be an adjustment mechanism, discussed in Part Four-III.B, that reconciles actual costs with projections.

144. Drs. Fisher and Horowitz recommended an increase of $461.3 million, due to their conclusion that PREPA significantly has under-budgeted fuel expense. They recommended no change in the projected performance savings and no change in the purchased power expense. PREPA separately also updated its proposed revenue to reflect higher fuel prices.

145. In this section we discuss background facts on PREPA's fuel consumption and power purchases, describe its budgeting process for these costs, then evaluate the budgets and make findings. We address here only the reasonableness of these costs. We will address the method of cost recovery (*i.e.*, base rate vs. adjustment charge) in Part Three-III below.

1. Background facts on PREPA's fuel consumption

146. PREPA's generation fleet (*i.e.*, excluding the generation owned by its third-party suppliers of power) consists largely of fossil-fired generators. Apart from two units at the Costa Sur plant, all of PREPA's thermal generators burn either distillate fuel oil or residual

[124] The projected performance savings involve these categories: generation dispatch, fuel sourcing, fuel supply chain, spinning reserves, and forced outages.

fuel oil.[125] PREPA's combined cycle and gas turbine units burn mostly distillate and its steam units burn residual. Costa Sur units 5 and 6 burn a blend of natural gas and residual fuel oil.

147. PREPA's fuel mix has changed over time. In FY2011, residual represented 90% of the fuel burned by PREPA, with the remainder made up of distillate oil. In FY2012, PREPA started burning natural gas at Costa Sur. Gas today represents 27% of PREPA's total fuel use. Use of distillate has increased to approximately 20%, while PREPA's reliance on residual has declined, now representing half of PREPA's fuel consumption.

148. Since PREPA's generation fleet will remain largely the same in FY2017, the total fuel consumption and the shares of fuel types will resemble recent years.

149. PREPA's process for approving and overseeing fuel contracts involves multiple officials. They include the Treasurer, the Head of the Environmental Protection and Quality Assurance Division, the Fuel Office Manager, the Chief Financial Officer, the Director of Legal Affairs, the Operations and Infrastructure Manager, the Head of the Technical Services Division, the Head of the Division of Electrical Conservation and Protection Electric System, the Head of the Division of Electrical Distribution, and the Head of the Material Management Division. All fuel purchase contracts are signed by the Executive Director.[126]

2. Background facts on PREPA's power purchases

150. PREPA has two fossil PPOAs: one with EcoEléctrica, which operates a 507 MW, natural gas-fired combined cycle plant; and one with AES, which operates a 454 MW coal-fired steam plant.

151. PREPA's contractual terms with AES are straightforward. PREPA pays for the energy AES produces and the dependable capacity it provides. PREPA also compensates AES for its startup-related costs after any unit shutdown requested by PREPA. PREPA's energy payment to AES has two components: a fuel pass-through and a charge for variable operations and maintenance costs. The per-kWh energy price is fixed every year, subject to a guarantee from PREPA that the unit will be dispatched at a capacity factor of at least 50%. The capacity price reflects AES's capitals costs and its fixed operations and maintenance costs.

152. PREPA's contract with EcoEléctrica is more complex. It includes a capacity payment and a base energy charge (both of which are structured similarly to the AES

[125] Distillate is one common name for the No. 2 grade of fuel oil. It is also sometimes referred to as diesel fuel. Residual is one common name for the No. 6 grade of fuel oil. It has a higher viscosity than No. 2 fuel oil and may contain higher levels of impurities.

[126] Response to CEPR-RS-01-05 at 66. Commission's Fourth Request of Information (July 15, 2016).

contract, although unlike the AES energy charge, the EcoEléctrica base energy charge is adjusted based on the unit's heat rate at different levels of output). As with the EcoEléctrica contract, PREPA pays charges for unit start-up if PREPA requested the preceding shut-down. The EcoEléctrica contract also requires an "excess energy payment" for energy required above a 76% capacity factor. EcoEléctrica sets the usage level associated with the 76% capacity factor monthly and sets the excess energy rate weekly. These factors make it difficult for PREPA to predict its payments to EcoEléctrica.

153. PREPA has active contracts with several renewable energy providers. These contracts include ones with two wind farms, a landfill gas-fired generator and four solar farms. These sellers total approximately 157 MW of capacity. PREPA's contracts with renewable generators typically contain a base energy price with a yearly escalator, plus a payment for renewable energy credits ("RECs"). Our IRP Order detailed concerns with these contracts.

3. The budgeting process for fuel and purchased power

154. To budget fuel and purchased power costs for a given budget period, PREPA undertakes four main steps.

155. First, PREPA forecasts loads and fuel prices. For its FY2017 projections, PREPA relied on fuel price forecasts prepared by Siemens in February of 2016. Siemens described these forecasts as a "lower bound" on the expected trajectory of fuel prices.[127] In the Final Resolution and Order on the IRP, the Commission found that these forecasts were well below contemporaneous forecasts from credible public forecasts. According to the Fisher-Horowitz Report, the IRP Order's finding has been borne out. Prices have risen greatly. As shown in Table 28 of the Fisher-Horowitz Report, Siemens's fuel price forecasts were wrong.

156. Second, PREPA gathers cost data related to its Power Purchase and Operating Agreement ("PPOA") contracts. To represent PREPA's contract terms in PROMOD (the computerized production cost model to be explained shortly), PREPA makes several adjustments and assumptions. For the renewable contracts, PREPA inputs the contractual energy and REC charges, and uses a capacity factor of 21%. For its contracts with AES, PREPA models a fuel cost and a variable operations and maintenance ("O&M") cost, then separately inputs a capacity charge calculated as a combination of a fixed O&M cost and a capital cost. PREPA follows a similar process for the EcoEléctrica contract. Because the excess energy charge in that contract is determined periodically and unilaterally by the seller, PREPA's modeling of that charge is an educated guess. Our consultants reviewed PREPA's methods and confirmed their reasonableness.

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[127] CEPR-AP-2015-0002; IRP Technical Hearing, April 6, 2016, Nelson Bacalao, 00:14:15 of part 5 of the hearing recording.

157. Third, PREPA determines performance and operational cost data related to its own units.

158. Fourth, the foregoing information is input into PROMOD, a "production cost model" that determines an optimal (*i.e.*, lowest cost while still satisfying demand) dispatch pattern for all units on PREPA's system. PROMOD model forecasts the costs of production in detail—this output becoming PREPA's projected costs.

159. Drs. Fisher and Horowitz raised several concerns about PREPA's use of PROMOD, but felt that each concern was sufficiently small that necessary corrections could occur through the fuel and purchased power adjustors. The concerns were as follow:

1. PREPA used high minimum run times for its steam units, potentially leading to under-use of lower cost units.

2. PREPA assumed for Costa Sur a higher percentage of natural gas than current practice supports.

3. PREPA expects that in FY2017, EcoEléctrica's excess energy price will be lower than PREPA's variable cost of generation, more often than was the case in FY2016. That expectation led PREPA to model a frequent use of EcoEléctrica above the 76% threshold that triggers the excess energy price. Drs. Fisher and Horowitz saw no evidence to support this expectation. Of distinct concern was given the low availability and low flexibility of many of PREPA's units, PREPA would have difficulty committing them quickly to avoid a high excess energy price.[128]

4. While modeling the renewable contracts was mostly straightforward, the consultants found several exceptions involving deviations of modeled prices from contractual prices.[129]

4. Evaluation of PREPA's fuel and purchased power budgets

160. Fuel: Drs. Fisher and Horowitz found that PREPA's fuel spending in the first two months of FY2017 was double its projection. As a result, they recommend a major increase in PREPA's fuel cost for FY2017. Admitting their estimate is rough (and will be corrected through the fuel adjustor), they offered three estimating methods, displayed in Table 25 of the Fisher-Horowitz Report. The median estimate is a total, before performance savings, of $1,225,000,000. This new total requires increasing PREPA's proposed revenue requirement

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[128] One PREPA witness did assert that the excess energy price is not always something to avoid; sometimes it is a way to save money when that price is lower than PREPA's marginal cost.

[129] See Table 19 of the Fisher-Horowitz Report.

by $461,305,000. We adopt this level as reasonable, recognizing that deviations from this amount will be recovered through the adjustor clause. Attachment 1 reflects this adjustment.[130]

161. Purchased power: Drs. Fisher and Horowitz found that since FY2010, PREPA's predictions of its purchased power spending have been reasonably accurate—a conclusion that has held so far in FY2017. The renewable contracts present uncertainty—not due to their prices (which are contractual) but due to their output, because their online dates are difficult to predict. Embodying this uncertainty is a 21% drop ($30 million), after less than six months, in PREPA's expectations regarding spending on renewable energy contracts.[131] Taking all these facts together, our consultants found "no compelling cause" to adjust PREPA's total PPOA budget, and we agree. The revenue requirement shall reflect PREPA's proposed purchased power cost of $819,907,000.

Directives on fuel

1. ***PREPA shall increase its FY2017 fuels budget (and its revenue requirement) by $461,305,000, for a total FY2017 fuel budget of $1,117,273,000.***

2. ***As presented in its filing on Schedule A-6, PREPA proposed to include the following costs in the Fuel Adjustor: fuels (residual, distillate, natural gas, propane, additives), transportation, inspection, laboratories, storage, handling, delay, taxes, and hedging. PREPA has not incurred Fuel Expense for Additives in the last three fiscal years through FY2016. Nor has it incurred expense for Delays or Fuel Hedging in the last two fiscal years (FY2015 and FY2016). Before incurring such costs in the future, PREPA shall submit to the Commission a request for approval, containing the proposed amount and a justification, and await approval. All other categories of Fuel Expense proposed by PREPA shall be included in its revenue requirement.***

3. ***In the upcoming performance proceeding, the Commission will require PREPA to recommend to the Commission at least three firms to conduct a management performance review specifically relating to fuel purchase costs. These firms may be the same firms recommended for the purchased power review discussed below. The Commission will select one firm, which shall contract with PREPA to conduct the review under specifications established by the Commission. Such review shall contain, without***

[130] See also Attachment 3 at 5.

[131] See the IRP Final Order at Part IV(F)(4) for a discussion of Commission concerns about uncertainty involving renewables contracts.

limitation, a recommendation regarding procedures for periodic audits of PREPA's fuel procurement, to ensure that such costs are reasonable and accounted for properly.[132]

4. ***PREPA shall prepare fuel price forecasts at least semi-annually, submit them to the Commission and post them on its web site.***

Directives on power purchases

1. ***There are no adjustments to PREPA's projected FY2017 Purchased Power Expense.***

2. ***In the upcoming performance proceeding, the Commission will require PREPA to recommend to the Commission at least three firms to conduct a management performance review specifically relating to purchased power. These firms may be the same firms recommended for the fuel cost review. The Commission will select one firm, which shall contract with PREPA to conduct the review under specifications established by the Commission. Such review shall contain, without limitation, a recommendation regarding procedures for periodic audits of PREPA's power purchases, to ensure that such costs are reasonable and accounted for properly.***[133]

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[132] PREPA opposed the performance review process stating that such a review will inherently impose burdens and costs and the costs ultimately would be borne by customers. The Commission notes that an independent management performance review can produce significant cost savings from improvements, which are typically greater than the cost incurred in the review process. Moreover, the cost can be less and the customer benefits greater, if the review is conducted by a qualified and independent consultant that is selected by the Commission, rather than by the utility that is being investigated.

[133] Regarding the prices in existing renewable contracts, the Commission is not suggesting that high prices in existing renewable contracts reflect imprudent actions by PREPA or excess costs to consumers. Windmar argues that contracts signed in 2010-2012 preceded declines in renewable energy equipment, and occurred at a time when high oil prices made such contracts attractive to PREPA. Our point is not that PREPA necessarily should seek to terminate contracts, but to examine whether renegotiations can lower prices and also make operational dates more certain.

Sunnova and Windmar argue that PREPA's revenue requirement should include an amount for distributed generation RECs. They assert that PREPA has refused to comply with the Renewable Portfolio Standard established by Act 82-2010 by not acquiring all available RECs, and that PREPA owes penalties for non-compliance. Enforcing the RPS obligation—including determining the scope of that obligation—does not fall within the boundaries of this rate proceeding. The proper approach is to submit a complaint alleging specific facts and proposing specific remedies. To the extent the disposition of such a complaint changes PREPA's revenue requirement, the Commission would reflect such change in future rates.

3. ***Consistent with the requirement in our IRP Order, PREPA shall establish and update semiannually a database of its renewable energy contracts, for all projects whether or not operational. This database shall include the names, owners, contract numbers, initial energy costs, current energy costs, initial REC costs, current REC costs, any relevant escalators, and expected and actual on-line dates. The format used in response to CEPR-AH-03-02 is acceptable but not binding.***

C. Capital expenditures

162. PREPA proposes new capital expenditures in FY2017 of $336.6 million, to be collected from ratepayers in this fiscal year. The FY2017 amount consists of $232.1 million for maintenance capital, $56.3 million for the Aguirre Offshore Gasport ("AOGP") and $48.2 million for transmission and distribution projects.[134] This amount is comparable to PREPA's CapEx in FY2013 ($360.1 million) and FY2014 ($316.0 million), but is much higher than PREPA's CapEx in FY2015 ($201.1 million) or FY2016 ($140.4 million).

1. Challenges in projecting capital expenditures

a. The distinction between operating expenses and capital expenditures

163. A transparent approach to setting budgets and revenue requirements requires a clear distinction between a capital expenditure and maintenance expenditure.

164. Operating and maintenance ("O&M") expenses are the expenses required to run the utility day-to-day. For a utility's physical infrastructure (generation, transmission, and distribution), this category includes the repairs and maintenance customarily required to keep an asset operating efficiently and reliably. Accounting principles require recording these costs in the year incurred. Regulatory principles normally require these costs to be recovered from ratepayers in the year incurred.

165. Capital costs are, in contrast, long-lasting. They are associated with new units or equipment, or with expenditures that increase the useful life of an existing unit. Instead of being expensed in the year occurred, they are usually amortized (*i.e.*, spread over the life of the associated equipment). In that way, the customers who benefit are the ones that pay, rather than causing this year's customers to pay for benefits enjoyed by later customers.

166. For a deteriorated plant, the distinction between operating expense and capital expenditure is not always clear. Ordinary repairs might not keep it operational. Temporarily patching a boiler is an operational expense, because tbe patch will not last multiple years.

[134] See PREPA Ex. 3.0 at 45 and PREPA Schedule F-3 REV.

Replacing the boiler in the next major outage cycle is a capital expenditure because it will last multiple years. Many of PREPA's proposed expenditures fall into this second category.

167. Part Two-II.B explained that, until PREPA gains access to capital markets, today's ratepayers must pay for both types of expenditures, operating and capital, in the year incurred. PREPA ratepayers therefore will be paying currently for some capital projects in whole, paying this year's portion of projects begun before this year and continuing after this year, and paying for the first part of projects whose completion might not occur until a later year.

b. Spending ceilings unrelated to system needs

168. In recent years, PREPA has based its capital budget on a compromise between the system's actual needs and a desire to avoid any rate increase (recall there has been no base rate increase since 1989). As PREPA explained:

> Historically, there has been political pressure to not increase PREPA's rates in response to cost and investment needs and therefore PREPA has had to sacrifice needed capital expenditures in order to remain solvent and to not run out of cash.[135]

This annual compromise produced a "top down" figure—a total budget cap for all capital expenditures, one driven not by system needs alone but by political considerations arising from hesitance to raise rates (or pressure from political actors not to raise rates). In other words, the main question was not "What do we need to spend to fix our system?" but "Given the premise of no rate increases, what can we spend?" This approach produced the following capital expenditure budgets:

FY2010: $350 million
FY2011: $300 million
FY2012: $327 million
FY2013: $300 million
FY2014: $300 million
FY2015: $245 million
FY2016: $245 million[136]

169. Artificial caps hide the truth. In future rate proceedings, PREPA must reveal truth: the total cost that must be incurred to meet the quality standards to which our citizens

[135] CEPR-SGH-01-08 at 10. Commission's Second Request of Information (June 23, 2016).

[136] Fisher-Horowitz Report at 75. PREPA underspent its budgets in FY2015 and FY2016. See Fig. 15 of the Fisher-Horowitz Report.

are entitled. Total cost means total cost: emergency purposes, preventive maintenance, system improvement, and system expansion.

170. A distinct problem arises when PREPA allocates amounts from the total capped budget to various departments. We were told by PREPA that the practice, with some exceptions, has been to allocate to each department the lower of that department's historic budget or its prior year's actual spending. This approach assumes, incorrectly, that the weighting of priorities among departments does not change.[137] It also encourages each department to spend its budget fully to avoid a reduction in the next year. Neither result substitutes for an annual rethinking of priorities, performed rigorously. PREPA needs to improve its budgeting process: how it sets priorities and how it develops, organizes and stores the information needed to make the best decision. We will address these concerns in our pending investigation on PREPA's performance.

171. But for this first base rate increase in over twenty-five years, the Commission will not require ratepayers to pay for the full amount spending necessary to satisfy PREPA's infrastructure needs. To try to make up for years of under-spending would be too harsh for customers. Nor could PREPA spend those dollars efficiently, given the limited time remaining in the fiscal year and the shortage skilled workers. Furthermore, there needs to be more rigorous budgeting and recordkeeping before we approve higher spending levels. We emphasize, however, the "top-down" budgeting approach that we are forced to accept here must not and will not continue. Rather than continuing to spend in reaction to system breakdowns, PREPA must invest in a reliable future. At the Technical Hearing, most of PREPA's witnesses made clear that they are willing and ready to abandon the historic approach and embrace the right approach. This Commission will insist on PREPA's doing so.

c. The nature of Commission's review

172. PREPA's capital expenditure request for FY2017 lists 402 items, with stated amounts ranging from zero to $20 million. The items are diverse: refurbishing individual turbines or generators; building new poles and lines; acquiring advanced transmission and distribution equipment; ordering new utility vehicles, computer systems, and network equipment, among others.

173. A thorough evaluation of PREPA's budgeting and spending requires a team of engineers and auditors. These assets are not presently available to the Commission. Even if they were available, the short 180 days statutorily available for this first rate proceeding would have been insufficient to deploy them effectively. We will use the upcoming performance proceeding to deploy the necessary expertise. But in this proceeding it was not practical, or wise, to attempt to review the reasonableness of every dollar.

[137] However, it appears that some consideration is given to individual department requests arising from each department's determination of its needs. Directors ask for what they need; their requests are considered by top executives; then directors are given a budget amount.

174. Among the challenges facing the Commission was transparency. While PREPA made serious efforts to provide the information we required, answering hundreds of questions, the information provided was often insufficient. Documents did not always make clear the purpose of a capital project, its prior spending, its progress toward completion or the predicted final cost. Often PREPA presented for a project a single number representing spending for a single year. That number did not inform us about the past or the future, because a line item in the FY2017 capital budget is only a fraction of a larger project. One must understand the full picture: When did the project start, when will it end, and is the spending this year and thus far consistent with the total budget? Without this information, we cannot know the project's purpose, its reasonableness as a solution to a problem, or the reasonableness of the project cost. PREPA's presentation often left us unable to determine whether a project's progress and spending coincided with an established schedule.

175. Contributing to the problem was dispersed records. When asked for work orders or contracts for engineering, procurement and construction ("EPC") for projects, PREPA responded:

> PREPA does not have electronic systems configured to be able to assess automatically which work orders are associated with a particular [capital expenditure] project; most of this information is on paper records. And those paper records are not organized by project in a central location. Further answering, the process of preparing the [capital expenditure] budgets start in PREPA's transmission and distribution districts, generating plants, customer service offices, among others.[138]

PREPA further explained:

> The particular details of each project are managed locally, not at a central location. Once the final complied spending limits are met, the plan can go through the final approvals. Regarding projects with no money spent, any documents reflecting the corresponding justifications and related information is located in the multiple generation plants, distribution offices, customer service areas, and other offices or departments that are responsible for or use that [capital expenditure] project.[139]

176. This dispersion of information meant that PREPA could not provide sufficient documentation explaining a project, justifying its expense, how the estimate was generated, or even the project's value to customers. As our consultants explained, with respect to specific capital projects PREPA was often "unable to provide basic explanations, work-plans,

[138] CEPR-AH-02-02(c) at 1. Commission's Sixth Request of Information (July 29, 2016).

[139] *Id.*

or other due diligence documentation [...]". The consultants thus had to "assess separate records of generator operations, forced outages, historic spending, and explanations scattered across dozens of disparate data responses to even begin to gain a coherent view of the state of PREPA's system, their needs, and the value of the projects requested by PREPA."[140]

177. Given these limitations, the Commission focused on capital spending areas raising obvious questions, while accepting PREPA's other proposed numbers for this rate year. For the lack of organized documentation does not change the reality that more spending is necessary to fix PREPA's system. We grant the approvals below, however, subject to the strict condition that PREPA complies with the budgeting procedures and transparency requirements established throughout this Order.

* * *

178. In the following subparts we will address the proposed capital expenditures for each of the following areas:

Generating plant
Aguirre Offshore Gasport
Transmission
Distribution
Transportation and Computer Equipment

We will close by stating our overall findings on capital expenditures in the revenue requirement.

2. Generating plant

179. Part One-III described, in general terms, the deterioration of PREPA's generation fleet. Merely beginning the process of restoration—the minimum necessary to keep the system operating—will require hundreds of millions of dollars. For each of the major generating plant, we address first the challenges it faces, then address how PREPA's proposed capital budget responds to those challenges.

a. Aguirre steam units

180. Aguirre is a 1,492 MW plant near Salinas. It is the largest single plant in the PREPA system, making up 26% of PREPA's generating capacity. It has three subcomponents: a steam power plant (900 MW), a combined cycle power plant (520 MW), and a simple cycle power block (72 MW). The Aguirre steam power plant, built in 1975, is itself divided into two electrical generating units of 450 MW each, both fired by heavy fuel oil. These steam

[140] Fisher-Horowitz Report at 80.

units are the largest central station generators on PREPA's system, representing 16% of system capacity.

(i) Outage problems

181. Forced outages occur when a generator either automatically turns off or is brought offline for a mechanical, safety, or environmental problem or violation. A unit's high forced outage rate signals need for repair, chronic operational problem or susceptibility to operator error.

182. From 2012 to 2014 (calendar year), the Aguirre Steam Units on average had an unexpected outage during 612 hours, or twenty-five and a half days every year.[141] In 2015, Aguirre Steam Unit 1 suffered an extended outage from mid-July to the end of the year.[142] Aguirre Steam Unit 2 had another outage starting December 1st of 2015. The turbine remained offline through the last provided record in August 2016, for an outage of 246 days. The result was a combined forced outage rate of 27% in 2015 and 46% in 2016.

183. This record makes clear that PREPA's largest units are not reliable. Drs. Fisher and Horowitz concluded that "such sequential failures are not a function of normal wear and tear or aging, but are indicative of systematic maintenance failures, a failure to perform predictive maintenance, operational errors, and faulty repairs."[143]

(ii) Relationship to AOGP

184. The Aguirre Steam Units are not compliant with EPA's Mercury and Air Toxics Standard ("MATS"). PREPA's strategy for MATS compliance at Aguirre is to switch these units from oil to natural gas, using gas provided by the AOGP project (discussed in Part Two-III(C)(3) below). PREPA treats this conversion, along with the construction of the offshore gasport and associated facilities, as a single capital expenditure. But the Aguirre Steam Units need capital expenditures regardless of their connection to AOGP.

185. Determining the reasonableness of these expenditures is complicated. On the plus side, improving these units' performance will improve PREPA's reliability, while avoiding the need to operate more expensive backup units. On the negative side, extending the Aguirre units' lives will not be economical if the Commission ultimately rejects AOGP in favor of replacing the Aguirre units. Under PREPA's IRP plan, the Aguirre Steam Units would retire in 2026 and 2027, respectively.[144] With this plan (which assumes AOGP), continued

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[141] CEPR-JF-01-16 Attach 02 at 3. Commission's Sixth Request of Information (July 29, 2016).

[142] *Id.* Log of forced outages.

[143] Fisher-Horowitz Report at 90.

[144] PREPA Base IRP (August 17, 2015). Table 7-4.

capital investments make sense, to ensure reliable operation for another decade. But if the upcoming AOGP Economic Analysis causes the Commission to reject AOGP in favor of other options, logic dictates making only those investments at Aguirre necessary to ensure continued operation and reliability for the units' remaining lives.

(iii) Proposed capital expenditures

186. For FY2017, PREPA estimates $27 million in capital expenditures at the Aguirre Steam Units. That one-year cost is part of a multi-year project. For FY2017-2019, PREPA anticipates capital expenditures of $65 million, mostly for rehabilitating turbines and boilers. The $27 million amount represents both the tail of spending begun in prior years, as well the start of spending for projects expected to extend through FY2018 and FY2019. Combined with the natural gas conversion projects, PREPA is planning on spending $114 million in capital on the Aguirre Steam Units between FY2017-2019. The spending discussed here accounts only for projects that are currently planned in the next two years. There is a possibility that between now and 2019, PREPA will plan, scope and budget for additional capital projects at the Aguirre Steam Units.

187. PREPA has already started a series of retrofits of the boiler, turbine and generator at Aguirre Unit 2. While PREPA says these efforts aim to extend that unit's useful life, the turbine rehabilitation effort coincides with the failure of the turbine in November 2015.[145] Our consultants concluded that PREPA requires at least minimum capital to keep these units available while the Commission determines whether they should be continued through 2027 or be replaced sooner.

188. Drs. Fisher and Horowitz stated they were unable to assess whether the amounts proposed by PREPA matched well with the specific proposed projects. They did find, however, that PREPA's total anticipated expenditure at the Aguirre Steam Units, averaging $24/kW from 2017-2019 for non-AOGP projects, was consistent with "run-rate" capital dollars budgeted for steam coal units at other utilities.[146]

b. Costa Sur steam units

189. Costa Sur Plant is a 990 MW plant near Guayanilla. It is the second largest single plant in the PREPA system, making up about 17% of PREPA's capacity. It consists of four steam boiler electrical generating units: two sized at 85 MW and two sized at 410 MW.[147] The Costa Sur units are designed to be fired by residual fuel oil (No. 6).[148] Since 2012, Costa

[145] CEPR-JF-01-16 Attach 02 at 3. Commission's Sixth Request of Information (July 29, 2016).

[146] Fisher-Horowitz Report at 94.

[147] PREPA Base IRP, August 17, 2015. Table 3-1.

[148] *Id.*

Sur Units 5 & 6, the larger units at the plant, have been fired with approximately 60-80% natural gas acquired from Gas Natural Fenosa, the majority owner of the EcoEléctrica power plant.[149] The fractions of gas and oil burned at Units 5 & 6 has varied over time, but is rarely less than 60%.

(i) Operations

190. For the last five years, the larger two units at Costa Sur have operated with an average capacity of 65%, making them the highest utilization units on the PREPA system. From calendar year 2012 through 2015, they maintained an average availability of 97%.

191. The smaller two units at Costa Sur, 3 & 4, are not MATS-compliant. To comply with MATS, PREPA has designated these units as "limited use," requiring them to operate below an 8% capacity factor starting in FY2016. In FY2016 Costa Sur 3 had a capacity factor of 11.3%.

(ii) Proposed capital expenditures

192. PREPA anticipates spending $7.4 million on capital improvements at Costa Sur Units 5 & 6 in FY2017. As the plant moves into a seven-year overhaul cycle, that level will increase through FY2020, due to investments in boilers and turbines, and modifications to the cooling intake and discharge systems to meet environmental regulatory requirements. PREPA does not propose any capital expenditures at Costa Sur 3 & 4, even though these units were used in FY2016, and even though PREPA's long-term plans designated these units for backup capacity.

193. Drs. Fisher and Horowitz concluded that the proposed capital expenditures for the boiler and turbine refurbishment are in line with similar projects envisioned by PREPA and seen elsewhere. They also found that PREPA's total anticipated spending at the Aguirre Steam Units, averaging $16/kW from 2017-2019, are in line with "run-rate" capital dollars budgeted for steam coal units at other utilities.[150]

c. Palo Seco steam units

194. The Palo Seco Plant has four large generating units located about two linear miles from downtown Old San Juan. Palo Seco's arrangement resembles Costa Sur's, but is smaller. Palo Seco 1 & 2 are 85 MW each, while Palo Seco 3 & 4 are 216 MW each. PREPA maintains simple cycle turbines at the Palo Seco site. Palo Seco was designed to be fired by heavy fuel oil (No. 6). At 602 MW, the Palo Seco Plant is PREPA's fourth largest plant, making

[149] Percentages by equivalent heat content. CEPR-AH-06-01at 1. Commission's Fourteen Request of Information (September 30, 2016).

[150] Fisher-Horowitz Report at 97.

up about 10% of PREPA's capacity. These units are a fundamental part of PREPA's northern fleet.

(i) MATS compliance and forced outages

195. Palo Seco's steam units are not MATS-compliant. PREPA has designated the two smaller units as "limited use," but the larger units lack a specific compliance strategy. PREPA has stated that "Siemens assumes that PREPA enters into a settlement agreement with EPA regarding Palo Seco 3 & 4 steam units (with a total capacity of 432 MW) allowing these units to continue operation burning No. 6 fuel oil through December 31, 2020. After that they will be either replaced or designated as a limited use unit."[151] Under this strategy, PREPA must be able to replace the Palo Seco units expeditiously.

196. The "limited use" designation for Palo Seco 1 & 2 required those units to operate at a capacity factor below 8%, starting in April 2015. But in FY2016, both units had capacity factors of 39% and 44%, respectively.[152] PREPA has explained that for Palo Seco 1 & 2 to satisfy the "limited use" designation, PREPA's other units, particularly those at San Juan and Palo Seco, need to be operating consistently. They are operating inconsistently. Palo Seco 3 & 4 had substantial outages, while PREPA does not expect Palo Seco 4 to be back in full service until January 2017.[153]

197. Palo Seco 3 & 4 has suffered outages exceeding those at the Aguirre Steam Units. Like Aguirre, Palo Seco experienced marked increases in the forced outage rate in 2014 and 2015. In 2015, Palo Seco's steam units was available about 65% of the time; in 2012 and 2013 their availability was 97% and 94%, respectively. At least as of August 2016, Palo Seco 4 has remained out of service.[154] Overall, Palo Seco 4 stayed on forced outage for over a year and a half, with only two months of actual operation in that time. Palo Seco 3 has had a similar history of forced outages, beginning in October 2015.[155]

(ii) Proposed capital expenditures

198. For FY2017, PREPA proposes capital spending at Palo Seco Units 3 & 4 of $8.5 million. The largest single project, PID 13448 ("Turbine Generator Improvement") is a

[151] PREPA Base IRP, August 17, 2015. Section 7-5.

[152] CEPR-AH-03-07 Attach 01 at 5. Commission's Seventh Request of Information. (August 12, 2016).

[153] CEPR-JF-01-10(c) at 7. Commission's Sixth Request of Information. (July 29, 2016).

[154] CEPR-AH-06-06(a)at 6. Commission's Fourteen Request of Information. (September 30, 2016)

[155] CEPR-JF-01-16 Attach 02 at 3. Commission's Sixth Request of Information. (July 29, 2016).

full overhaul of the turbine at Palo Seco 4 to bring it back to service. PREPA has not proposed capital expenditures at Palo Seco 1 & 2, even though it intends those units to provide backup capacity as "limited use" units. Drs. Fisher and Horowitz state it is unclear whether these units can stay within 8% capacity factor, given the need for generation in the north due to outages at PREPA's other northern plants.[156]

d. San Juan Steam units

199. The San Juan Steam Plant has four 100 MW steam units. They were built between 1965-1969, making this plant PREPA's oldest. The San Juan Steam Units were designed to be fired by residual fuel oil (No. 6).

(i) MATS compliance and forced outages

200. PREPA intends to designate San Juan 7 & 8 as "limited use." It is also seeking leniency for San Juan 9 and 10. PREPA has argued that it cannot designate San Juan 9 & 10 as limited use because they are "critical reliability units." PREPA plans to convert them to "burn natural gas on a dual-fuel scenario with Bunker C [No. 6] fuel oil."[157]

201. That conversion to natural gas would require a source of natural gas, but PREPA has stated: "While gas to the North could potentially be achieved via LNG infrastructure in the North or a South-to-North gas pipeline, the feasibility of either option is yet to be evaluated."[158] In the meantime, for the last five years San Juan 7 & 8 have operated at a 60% capacity factor, well above the 8% cap for "limited use" status.

These inconsistencies leave us with uncertainties. The following questions remain unanswered:

1. What PREPA can do to achieve reasonable MATS compliance at San Juan Plant.

2. What steps PREPA is taking to achieve MATS compliance at San Juan 9 & 10.

3. What expectations have been set with EPA with respect to MATS compliance at San Juan 9 & 10.

4. Whether PREPA still relies on the assumption that San Juan 9 & 10 will be converted to natural gas with a "gas to the north" scenario.

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[156] Fisher-Horowitz Report at 100-101.

[157] CEPR-JF-01-10 Attach 01. Early Notice of Compliance Plan, Mercury and Air Toxics Standards ("MATS") pages 9-10. Commission's Sixth Request of Information. (July 29, 2016).

[158] PREPA 2015 Integrated Resource Plan, Section 6.3.1.

5. How the suboptimal operational record at San Juan 10 comports with PREPA's assertion that this unit is critical for reliability in the north of Puerto Rico.

6. How PREPA expects to meet the limited use designation for San Juan 7 & 8.

Like Palo Seco and Aguirre Steam Plants, San Juan Steam Plant has experienced increases in forced outages in the last two years.[159] In calendar year 2015, San Juan 10 had effective availability of about 18%. The unit is still offline and PREPA does not expect a return to service until mid-2017.[160] San Juan 9 had a series of outages in mid-2015, but has generally remained serviceable over the last six months with relatively minor outages. San Juan 7 & 8 have maintained better availability than the other units.

(ii) Proposed capital expenditures

202. For FY2017, PREPA proposes to spend $200,000 at all of San Juan Steam Plants (for FY2019 PREPA proposes to spend $15 million for improvements to the turbines and boilers at San Juan 9 & 10). Drs. Fisher and Horowitz concluded that the low spending level for FY2017 is inconsistent with these units' reliability problems, given their stated critical role. They reason that if these plants are not needed for reliability, they should be retired; if they are needed, then small dollars will not solve their large outage problems.[161]

e. Aguirre and San Juan combined cycle units

203. The Aguirre and San Juan Combined Cycle ("CC") Units are the only combined cycle units in PREPA's current fleet. They are composed of combustion turbine ("CT") units and heat recovery steam generators ("HRSG"). These components enable them to use the waste heat produced by the combustion turbine to create additional electricity. Both sets of combined cycle units burn diesel fuel. The two Aguirre CC units have nameplate capacities each of 296 MW; PREPA rates each at 260 MW, for a total of 520 MW. The units were built in 1977 and have a very high heat rate (*i.e.*, low efficiency, in terms of amount of fuel necessary to create a unit of electricity). The two San Juan CC units have nameplate capacities each of 220 MW, but are rated by PREPA at 200 MW for a total of 400 MW. The units were built in 2008 and 2009. As newer units, they have relatively low heat rates (*i.e.*, high efficiency).

204. PREPA did not provide forced outage records or estimates for the Aguirre Combined Cycle units. PREPA's 2015 IRP did model a forced outage rate of 20%.

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159 Fisher-Horowitz Report at 102.

160 CEPR-JF-01-10(c) at 7. Commission's Sixth Request of Information. (July 29, 2016).

161 Fisher-Horowitz Report at 105.

(i) Plans for these units

205. In its IRP decision, the Commission ordered PREPA to pursue permitting and start a competitive bidding process for the repowering of the Aguirre 1 and 2 CC units with new, dual-fuel capable turbines.[162] Neither the repowering nor the planning or permitting costs for the repowering are part of PREPA's petition for a FY2017 rate increase.

206. In its 2015 IRP submission, PREPA proposed to convert the Aguirre CC to operate as a gas-fired facility starting in 2018, with the conversion coinciding with AOGP. PREPA's rate proposal includes the gas conversion at Aguirre CC with the AOGP project. PREPA has not yet signed a contract for this work, but has had informal discussions with General Electric.

(ii) Proposed capital expenditures

207. According to Drs. Fisher and Horowitz, the Company's modeling indicates that a repowered Aguirre CC unit, operating with a lower heat rate and better reliability, can support a plan to retire the Palo Seco and San Juan steam units. Yet PREPA proposes to spend on Aguirre CC only $17.8 million from FY2017 to FY2019, mostly for scheduled maintenance and "automation" systems. This amount is comparable to what PREPA spent in FY2016—yet according to Drs. Fisher and Horowitz, outages at Aguirre CC are preventing this unit from contributing reliably. PREPA seeks to make the gas conversion of the Aguirre CC a key component of the AOGP project and gasification of the south. These factors are in conflict with the low spending level proposed.

208. In contrast, at San Juan CC plant, PREPA proposes to spend $40.8 million from FY2017 to FY2019. One contributor to this cost is a maintenance contract from Mitsubishi-Hitachi ("MHPS-PR") to service the combustion turbines and generators (PIDs 16945 & 16946). This long-term agreement, signed in March 2016, extends and expands the scope of services provided by MHPS-PR from technical support and assistance to a full maintenance contract. Because this contract is specifically associated with the regular maintenance of the generator, the costs of this contract should be considered an operations and maintenance ("O&M") expense rather than a capital cost. One PREPA witness explained that if the unit is not in service, Mitsubishi does not get paid. This contract feature, he argued, reduces the need for a review of Mitsubishi's performance.

f. Cambalache and Mayagüez combustion turbine units

209. Cambalache and Mayagüez are two CTs (also known as "gas turbines") that burn diesel. Cambalache, near Arecibo on the northern central coast, has three power blocks of 83 MW each, totaling 249 MW. It was built in 1997-1998. Mayagüez station, located on the

[162] Final IRP Order, Part VII(B)(1)(c).

west coast, has four power blocks at approximately 50 MW each, or 200 MW. Mayagüez began operation in 2009.

(i) Outage problems

210. The Consulting Engineer's 2013 Report discussed a critical failure at the Cambalache plant when a control system fault led to the buildup of unburnt fuel in a turbine, leading to an explosion that severely damaged Unit 1.[163] The same report discusses more minor outages at Mayagüez, including an incorrectly installed turbine that required modification under warranty.

(ii) Expenditures on maintenance contracts

211. PREPA's proposed expenditures consist entirely of flat fees for "inspections" at Cambalache (PID 15880) and "improvement" at Mayagüez (PID 16978). At Cambalache, the inspection represents an ongoing service contract with Alstom, valued at $4 million per year. At Mayagüez, PREPA simply indicates a flat $600,000 per year "improvement." It is unclear why PREPA anticipates spending $4 million per year at the older, less efficient 249 MW Cambalache plant, while spending a much lower amount at the newer, more efficient Mayagüez station.

212. The primary spending at Cambalache is a maintenance contract with contractor Alstom Caribe (now a division of GE Power). The twelve-year contract, signed in May 2011, is designed to provide an inspection and refurbishment of combustion turbines and generators every two and a half years. Like the San Juan CC maintenance contract, Alstom divides maintenance into cycles, denoted as "A" through "D" inspections. "A" inspections occur approximately every month and a half (1,000 hours) and include preventative maintenance. "B" inspections occur every year and half (12,500 hours) and include the disassembly of the turbine unit for closer review. "C" inspections, every two and a half to three years (25,000 hours), include the refurbishment of the turbine and combustion chamber. Finally, "D" inspections, every five to seven years (50,000 hours), entail the refurbishment or replacement of any worn component in the generator or turbine.[164] The maintenance contract at Cambalache is specifically geared to the "C" inspection cycle.

213. Maintenance responsibilities under the contract are split between PREPA and Alstom, where Alstom provides turbine cleaning, inspection and refurbishment services, but

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[163] URS June 2013 Annual Report at 27.

[164] *Id.* at 6-7.

PREPA "employees are responsible for the installation of replacement parts,"[165] and day-to-day operations and site maintenance.[166]

214. The "C" inspections provided under this contract fall into standard ongoing maintenance cycles. Because this contract is specifically associated with the regular maintenance of the generator, the costs of this contract should be treated as an O&M expense rather than a capital cost.

215. While the contract requires that Alstom provide a "permanent on-site operations and maintenance advisor,"[167] and provides a "technical field advisor" for "A" and "B" inspections, the contract does not actually specify the role of the technical field advisor, who leads the inspection and refurbishment process and, most importantly, who bears responsibility for correctly executed inspections, maintenance, and replacement.

216. The contract limits Alstom's liability for PREPA staff negligence or deficiencies. Alstom included a contract provision "exclud[ing] any and all liquidated damages for outage schedule delays, unless such delay is 100% attributable to a negligent act or omission of ALSTOM (*i.e.*, ALSTOM fails to deliver a correct part or make available the required personnel and such late delivery/performance causes an outage delay)."[168]

217. Since PREPA did not provide a record of forced outages at Cambalache, including any reasons for outages or delays, the Commission's consultants were unable to evaluate Alstom's performance. There was a two-year outage at Cambalache arising from a control system failure that caused an explosion in the turbine.[169]

218. According to our consultants, the Cambalache contract has no performance incentives or penalties to keep the units in operation or in a state of good repair. Alstom's liabilities are limited to a small fraction of the cost of the contract.[170]

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[165] *Id.* at 26.

[166] Alstom Cambalache 2011 Contract at ¶ 1.5 and Appendix 1.

[167] *Id.* at ¶ 1.1(h)

[168] *Id.* at ¶ 1.1(f).

[169] URS June 2013 Annual Report, Page 27.

[170] Alstom Cambalache 2011 Contract at ¶ 8.3.

Directives

1. *The FY2017 revenue requirement shall include the full proposed capital spending at Aguirre, Costa Sur 5 & 6, Palo Seco, and San Juan Steam Plants, as well as the $600,000 FY2017 improvements at Mayagüez.*

2. *PREPA shall remove the maintenance contract at San Juan CC from the capital budget and reassigned it as an annual maintenance expense, a reassignment of $12 million in FY2017 from capital to O&M. PREPA shall remove the cost of the Cambalache maintenance contract from the capital budget and reassign it as an annual maintenance expense—a reassignment of $4 million in FY2017 from capital to O&M. Attachment 1 shows increased PREPA's Generation Expense by $16 million, as discussed above.*[171]

3. *PREPA shall track capital expenses associated with each generating unit designated as "limited use." Such tracking shall be performed for each individual unit. To the extent capital expenditures at a plant site are not separable by unit, PREPA shall associate those expenditures in the tracking record by the units that benefit from the capital or, if applicable, designate an expenditure as "whole plant." In addition to, or as part of this tracking, PREPA shall:*

   a. *submit periodic reports on capital projects at Palo Seco 1 & 2, regardless of whether these units are designated "limited use."*

   b. *submit periodic reports on capital projects at San Juan 7-10, regardless of whether these units are deemed "limited use."*

   c. *submit periodic reports on capital projects at Costa Sur 3 & 4, regardless of whether these units are deemed "limited use."*

4. *PREPA shall submit strategic plans for the San Juan and Palo Seco steam plants, including the following elements, at a minimum: maintenance plan, MATS compliance plan, and an investment plan for maintaining or retiring San Juan 7-10 and Palo Seco 1 & 2. These plans shall be informed by a reliability study, assessing what strains are placed on the generation and transmission system in the presence or absence of the San Juan or the Palo Seco steam units.*

5. *PREPA's long-term modeling, including for integrated resource planning, shall consistently assess whether each generating unit designated as*

[171] See Attachment 3, at 3.

"limited use" is available for reliability purposes; and if not, assess the value of maintaining units that neither contribute to peak purposes nor provide energy to the system.

6. *In its next submission within the integrated resource planning process, PREPA shall assess the economic value to ratepayers of maintaining each "limited use" unit, as compared to retiring such unit.*

7. *In the upcoming performance proceeding, the Commission shall consider whether to require PREPA submit to the Commission at least three qualified consultants, one of which the Commission will select and retain, to:*

   a. *examine the maintenance contract at San Juan combined cycle plants and the performance of MHPS-PR to determine if the contractor is meeting performance expectations for maintenance service.*

   b. *examine the Cambalache contract and the performance of Alstom to determine if the contractor is meeting performance expectations for maintenance service at Cambalache.*

8. *PREPA shall submit for Commission approval, prior to its execution, any long-term contract with service providers with a potential net present value of $25 million or higher.*

9. *PREPA shall submit a summary of the expenditures necessitated by the fire and outage occurring in September 2016.*[172]

3. Aguirre Offshore Gasport

a. Overview

219. The Aguirre Offshore Gasport ("AOGP") is a re-gasification facility. Its purpose is to allow the Aguirre Steam and Aguirre Combined Cycle units (collectively "Aguirre Plant")

[172] PREPA opposes this requirement, arguing that the fire did not affect the revenue requirement in the current test year and that the Commission can investigate the costs in a future reconciliation proceeding. PREPA is missing the point, emphasized throughout this Part Two and articulated procedurally in Part Four: The Commission intends to avoid situations in which PREPA incurs costs first, then tells the Commission in a reconciliation proceeding that the Commission has no choice but to approve them because they have already been incurred. To protect consumers, the Commission must reserve its powers to evaluate costs before they are incurred. PREPA must not view the reconciliation process as allowing it to incur costs without accountability.

access to natural gas shipped to Puerto Rico as liquefied natural gas ("LNG"). As discussed here, AOGP includes four interlinked projects:

1. The offshore project: an LNG berthing platform and submerged pipeline connecting the offshore project to the Aguirre Plant site;

2. The onshore project: a pipeline from Jobos Bay to the Aguirre Plant facilities;

3. The combined cycle conversion project: the installation of natural gas burners and control equipment at Aguirre Combined Cycle Units 1 and 2; and

4. The Units 1 & 2 conversion project: the installation of natural gas burners, boiler modifications, and control equipment at Aguirre Steam Units 1 and 2.

On completion, AOGP's vendor, Excelerate, would dock a Floating Storage and Regasification Unit ("FSRU") at the offshore port. Arriving tankers would transfer LNG to the FSRU, which would decompress the LNG on an as-needed basis, shipping the decompressed natural gas through an undersea pipeline to the Aguirre Plant.[173] Permitting and engineering for the facility are ongoing.

220. PREPA says AOGP has four main benefits. It "would (1) contribute to the diversification of energy sources in Puerto Rico, (2) allow the Aguirre Plant to meet the requirements of the EPA's MATS rule, (3) reduce fuel oil barge traffic in Jobos Bay, and (4) contribute to energy price stabilization in the region."

b. Capital cost

221. PREPA proposes to include in its revenue requirement $56.3 million in FY2017 and $413.3 million in FY2018.

222. When it submitted its rate case request, PREPA estimated the total AOGP cost at $552 million, including financing costs. As detailed in the Fisher-Horowitz Report, that total has undergone several changes and re-estimates. The $552 million figure does not include the 15-year contract with Excelerate, a 15-year commitment at $40.7 million per year (present value of $422 million). Unlike all other capital expenditures in this rate case, PREPA believes it can secure financing for AOGP, assisted by a U.S. Department of Energy ("DOE") loan guarantee, which PREPA is seeking for 80% of the project cost.[174] The $56.3 million in FY2017 represents a portion of the costs for which PREPA has not requested financing

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173 Federal Energy Regulatory Commission, February 2015. Aguirre Offshore Gasport Project: Final Environmental Impact Statement (FEIS). Docket Nos. CP13-193-000 and PF12-4-000.

174 Dr. Quintana has stated that the DOE assistance is not the only possible financing path. Ex. 13.00 ll. 177-179.

support from DOE. Because the Commission will be limiting the FY2017 recovery to $15 million, we will defer a discussion of the budget details for when we make a final decision on the project.

c. Contracting

223. The Fisher-Horowitz report details the major contracts necessary to complete and operate AOGP, including contracts for the development of the offshore gasport itself ("Infrastructure Agreement"), the gas conversions of the Aguirre Plant units, the operation and maintenance of the gasport facilities ("Terminal Operation and Maintenance Agreement"), and the long-term rental of the FSRU facility ("Time Charter Party and LNG Storage and Regasification Agreement", or "Time Charter"), as well as other contracts for AOGP completion including engineering services, development of the environmental impact statement ("EIS"), the development and shepherding of other permits through Puerto Rico and federal agencies, and legal services.

d. Commission's IRP findings and PREPA's revised revenue requirement

224. In its Final Resolution and Order on PREPA's 2015 IRP, the Commission determined that it "cannot conclude that AOGP represents a least-cost, least-risk path for serving customers' needs and meeting Puerto Rico's energy policy goals based on the facts presented in this proceeding."[175] The Commission approved continued permitting, engineering and planning activities in the overall AOGP project, subject to a $15 million spending cap. PREPA must obtain Commission permission before exceeding that cap—permission that will be withheld until there is a "detailed economic assessment" of AOGP. PREPA has sought reconsideration.

225. On September 27, 2016, the Commission in the instant rate proceeding required PREPA to re-file its revenue requirement exhibits and testimony to, among other things, reflect the $15 million cap on AOGP spending. The Commission made clear that the $15 million cap "applies to the total combined spending associated with AOGP and the gas conversions."

226. PREPA's revised revenue requirement did not make the required adjustment. PREPA argued, among other things, that "even if AOGP and the other generation projects in the north are not approved, PREPA's other significant investments would have to be made rapidly."[176] PREPA concluded that it "has no reason to believe that these alternative

[175] CEPR-AP-2015-0002 (Sept. 26, 2016) at ¶ 255.

[176] PREPA Ex. 13.00 at ll. 110-111.

investments would be any less expensive than the investments currently reflected in its three year business plan."[177]

227. This argument was unaccompanied by supporting evidence. The Commission therefore will retain the $15 million cap. If and when PREPA needs to incur additional costs for AOGP, it shall first seek and obtain Commission approval through the AOGP Economic Analysis as specified in the IRP Order. Similarly, if PREPA needs to incur costs for "alternative investments" it shall seek and obtain prior approval from this Commission. The $15 million limit specified in the IRP Order is a limit not only on FY2017 spending, but on project commitments as well. Until such time that it has received Commission approval, PREPA shall take no action under any contract that increases its financial obligations beyond those that currently exist.

228. PREPA has argued that preventing progress on AOGP risks incurring EPA fines. This argument is nearly synonymous with an argument that AOGP is the only option for satisfying MATS, such that rejecting AOGP make EPA finds certain. The Commission rejects that argument because it is unsupported by facts. PREPA itself has included no amounts for fines in its proposed revenue requirement. When the Commission receives from PREPA the economic analysis required by the IRP Order, and if based on that analysis the Commission finds that AOGP is the most cost-effective path to MATS compliance, it will reconsider PREPA's argument. And when PREPA has credible evidence that such fines are imminent, instead of generalized statements that do not take into account EPA practices and precedents on fines, it should bring that information to the Commission.

229. The Fisher-Horowitz Report states (at 131):

> [I]n the time that PREPA committed internally to the AOGP project it increasingly sidelined viable alternatives, including MATS-compliant new generation, environmental controls on existing generation, increased renewable penetration, a focus on smaller distributed generation, or the completion of a south coast gas pipeline. PREPA has presented little or no evidence that those options are not still viable.

230. PREPA's emphasis on AOGP has come at the expense of a permitted, licensed, and half-built pipeline from the EcoEléctrica facility to Aguirre. As Ms. Miranda stated, "based on the previous studies that we did to justify this project, the cancellation of the south gas pipeline in 2009 was not optimal."[178] As our consultants explained, PREPA has "narrowed its options for improving and expanding the current MATS-compliant fleet, and

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[177] *Id.* at ll. 106-116.

[178] CEPR-SGH-001-016(a)-Supplemental at 22. Commission's Second Request of Information (June 23, 2016).

seeking substantial renewable energy."[179] Instead, by relying on Aguirre, PREPA has "created a fleet that, by its own measure, cannot effectively take on renewable energy simply because its existing generators ramp too slowly."[180]

e. Directives

(i) Consistent with the IRP Order, PREPA shall limit spending on AOGP to $15 million, reducing FY2017 revenue requirements by $41,340,000.[181]

(iii) PREPA shall not sign a Limited Notice to Proceed or a Final Notice to Proceed at AOGP until it has submitted, and the Commission has approved, the AOGP Economic Analysis; or until the Commission resolves the Reconsideration under review.[182] ***PREPA shall make no other commitments to incur future costs relating to AOGP without submitting a request and documentation to the Commission. If the Commission approves AOGP, PREPA may request an increase in the revenue requirement.***

(iv) The Commission recognizes, as the Fisher-Horowitz Report says, that "[s]talling projects, cancelling vendors, or missing contractual deadlines could result in increased costs, damages, or potential legal actions by vendors." PREPA shall alert the Commission promptly—and factually—if such possibilities become imminent realities.

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[179] Fisher-Horowitz Report at 39.

[180] *Id.* at 39.

[181] *See* Attachment 3, page 2.

[182] PREPA in its brief opposes this requirement on grounds that it is an issue pending in the IRP case. The Commission is imposing the requirement in this case to prevent PREPA from spending money that would then appear in a future request to increase customer rates, which increase would likely be accompanied by a PREPA argument that the Commission has no choice but to approve the increase because the costs already have been incurred. This type of situation is precisely the type that Dr. Hemphill never solved (see Part Four), and which PREPA's opposition here reveals to be a problem.

(v) If and when PREPA needs to incur additional costs for "alternative investments" (i.e., alternatives to AOGP), it shall first seek and obtain Commission approval. [183]

4. Transmission

a. Description of the transmission system

231. PREPA's transmission system consists of aerial and underground wires. It interconnects PREPA's large, central station generating plants, sited in four main locations in the north and south, with a distribution system serving population centers. The transmission system runs through mountains and wet tropical forests—some of the most difficult terrain in the U.S. As described in the URS 2013 Report (at 3):

> The Authority's transmission system is an interconnected network of 230 kV, 115 kV, and 38 kV power lines that carry electrical power from the production plants to numerous distribution centers from where it is distributed to clients for consumption.
>
> At the close of fiscal year 2013, the transmission system was comprised of 2,478 circuit miles of lines: 375 circuit miles of 230 kV lines, 727 circuit miles of 115 kV lines, and 1,376 circuit miles of 38 kV lines. Included in the transmission system totals are approximately 35 miles of underground 115 kV cable, 63 miles of underground 38 kV cable and 55 miles of 38 kV submarine cable. In addition to the high voltage lines, the transmission system includes transformers at the generating plant substations, transmission centers for interconnection of different voltage systems and switch yards and gear for connection or separation of portions of the transmission system operating at the same voltage. High voltage transformers installed in the Authority's transmission system and its production plants have a total transformer capacity of 19,207 MVA.

The Fisher-Horowitz Report adds:

> The 230 kV system essentially forms a ring around the island's less populous interior, connecting major cities and towns. In addition, PREPA maintains two substantial north-south corridors from Salinas (near Aguirre and the AES plant) to San Juan, and from Guayanilla (near EcoEléctrica and Costa Sur) to Arecibo and Manatí on the north coast. The primary operational thermal

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[183] Windmar argues that PREPA should retire obsolete power plants and study replacing them with smaller, flexible and more efficient plants as required by Act 57-2014. This is an important recommendation that is consistent with the recommendations in the Fisher-Horowitz Report, our conclusions in this Order and the directions stated in our recent IRP Order.

generation in Puerto Rico is located on the south coast EcoEléctrica, Costa Sur, Aguirre, and AES coal plant. The transmission system is designed to facilitate the flow of energy from these plants to the primary population centers in the north. Cambalache, on the north coast near Arecibo, and Mayagüez, on the west coast, provide peaking generation.

b. Transmission system capital budget

232. PREPA proposes a FY2017 transmission revenue requirement of $81.3 million, spread over 100 separate line item projects.[184] About 68% of the proposed FY2017 spending is concentrated in the 230 kV and 115 kV systems, primarily on line rehabilitation. The proposed cost is about $50,000 per mile in FY2017 for those larger systems, less for the 38kV system.

233. Half of the FY2017 dollars proposed for transmission ($40.5 million) would replace structures, towers, foundations and insulators on high capacity transmission lines, including those in the following corridors:[185]

1. Two 230 kV lines (50900, 51000) from Aguirre to Aguas Buenas, just south of San Juan (south-north): $15.7 million.
2. 115 kV line (37800) from Jobos near AES to San Juan (south-north): $13.4 million
3. 115 kV line (37400) from Arecibo to San Juan (east-west): $4.4 million.
4. 115 kV line (36100) from Lago Dos Bocas towards Piñas, on the outskirts of San Juan. (east west): $7.0 million.

As in all of PREPA's other capital projects, these numbers represent the amounts to be incurred in FY2017, rather than total project costs. Drs. Fisher and Horowitz state that based on project data, PREPA expects to spend ultimately (not in FY2017 alone) about $600,000 per mile on the 230 kV system and, on average, about $700,000 per mile on the 115 kV system. Drs. Fisher and Horowitz view these costs as consistent with utility estimates for similar projects.

234. The largest component of the 38 kV capital budget for FY2017 is allocated to the rehabilitation of the 38 kV system. This category has 24 specific projects, only one of which exceeds $1 million. These smaller projects are described by PREPA as "improvements" and

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184 See the Fisher-Horowitz Report at Table 15, consolidating PREPA's transmission capital budget by sub-area and initiative. See also PREPA's Schedule F-3 REV.

185 Schedule F-3 REV.

"increase[s] [in] capacity." Our consultants found that these projects, and their costs, are consistent with PREPA's needs to strengthen the system. The only project exceeding $1 million in FY2017 is a reconstruction of seven miles of line near Mayagüez (PID 15610). This project replaces rotting wooden poles with steel, effectively re-building the line. The Fisher-Horowitz Report states that the cost is consistent with utility estimates for similar projects.[186]

235. In addition to the foregoing line-related costs, there are assorted non-line items, most of which according to Drs. Fisher and Horowitz are lower-cost, individual items whose reasonableness is difficult to assess without an engineering audit.

c. Directive

Based on the information provided by PREPA and its examination and assessment in the Fisher-Horowitz Report, as well as the discussion at the technical hearing, the Commission approves the full FY2017 transmission system capital budget as requested by PREPA.

5. Distribution

a. Description of the distribution system

236. The PREPA distribution system is divided into seven regions with 26 Technical Districts.[187] From the 2013 Consulting Engineers Report (at 17):

> As of June 30, 2013, the Authority's distribution system consisted of approximately 31,550 circuit miles of distribution lines (with operating voltages ranging from 4.16 to 13.2 kV) and 333 substations (with a total installed capacity of 5,018 MVA). The distribution system has more than 1,800 circuit miles of underground lines. The Authority has 22 portable transformers with a total capacity of 349.6 MVA to substitute for existing transformers during maintenance or outages; similarly, the Authority has two portable capacitor banks each rated at 18 MVAR. There are 813 privately owned substations (with a total installed capacity of 3,266 MVA). The distribution system also includes approximately 1,485,200 client meters.

237. Of the 31,550 circuit miles of distribution lines, approximately 24% are at 13.2kV, 24% at 8.32 kV, and the remaining overhead lines are at 4.16 kV.[188] Over 16,000

[186] Fisher-Horowitz Report at 139.

[187] CEPR-AH-02-06 at 8. Commission's Sixth Request of Information (July 29, 2016).

[188] URS June 2013 Annual Report at 55.

circuit miles are primary voltage.[189] In addition PREPA has approximately 3,100 circuit miles underground, three-quarters of which is 13kV.[190] PREPA also has approximately 333 substations. According to the URS 2013 Report:[191]

> The Authority has standardized on two sizes of permanent substations based on the transmission system supply voltage. This standardization expedites the engineering, procurement, and construction cycle, increases flexibility in potentially utilizing equipment as spares, and provides a cost effective installed capacity margin for load growth. In situations where the Authority needs additional substation capacity on an interim basis or with short lead times, the Authority installs temporary substations that are standardized unitized metal clad equipment, which can be relocated as required.

As with the transmission system, PREPA emphasizes the need for repair:

> In general, PREPA Distribution system is in operational state or condition, but with reliability concerns, due to aging of the components. Still a high percentage of overhead ("OH") distribution circuits are attached to wood poles in deteriorated conditions, with OH cables gages inappropriate to serve the electrical load in a reliable and qualitative manner. Taking a look to the underground ("UDG") Distribution circuits, a significant number of them have been replaced in "temporary" way by OH circuits thru street lights poles, to reestablish electrical service to customers when outages cannot be fixed repairing the UDG conductor. Most of the UDG circuits in residential communities (Urbanizations) with more than 30 years of existence are direct burial, which accelerate the cable deterioration and prevent replacing cables in reasonable time and avoid repeated interruptions in the future. This also increases the reconstruction and maintenance costs when intervention is required. In addition to the Distribution Electrical network (OH &UDG), the sites (substations) where main power distribution transformers reside are in advance state of deterioration. Most of the components need to be replaced and perform continuous maintenance to grounds and buildings.[192]

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[189] CEPR-AH-02-01 at 1. Commission's Sixth Request of Information (July 29, 2016). Primary voltage lines link transmission substations with transformers, which "step down" the electric current to secondary voltages so that it can be delivered to customers

[190] CEPR-JF-02-06(a) at 22. Commission's Seventh Request of Information (August 12, 2016).

[191] URS 2013 Report at 51.

[192] CEPR-AH-02-01(f) at 3. Commission's Sixth Request of Information (July 29, 2016).

b. Distribution budget in general

238. PREPA proposes a FY2017 distribution capital budget of $74 million, spread over 108 line items. About 85% of the $74 million is for non-meter spending. Table 16 in the Fisher-Horowitz Report organizes the budget by sub-area and initiative.[193]

239. According to Drs. Fisher and Horowitz, most of the proposed spending is for rehabilitating the existing distribution system, substations, feeders and lines.[194] The spending includes $27.3 million for "blankets"—pools of money used as needed for repairs, maintenance and replacement parts. Another $12.5 million is allocated to new meters and meter equipment. The remainder (slightly over 50%) is targeted towards street lighting, along with rehabilitation of substations and feeders.

240. Of the 78 distribution projects that had FY2017 spending and were not either explicitly blankets or meters, the average FY2017 cost was well under one million dollars, with a median cost of about $250,000.

241. Assessing the reasonableness of these dollars was a challenge. Beyond calling them "required improvements," PREPA did not provide justification or explanations for the individual projects. Furthermore, PREPA's records of past capital spending were categorized differently from those associated with future spending. In a public technical conference call, however, PREPA's distribution staff answered questions thoroughly, in the opinion of Drs. Fisher and Horowitz, stressing that (a) the requested spending level was a necessary beginning to restoring the distribution system, and (b) the capital budgets were likely lower than required to ensure reasonable service. At the technical hearing, PREPA's witnesses re-emphasized these points.

c. Meter capital budget

242. PREPA has 1,620,401 installed meters, active and inactive.[195] For its FY2017 through 2019 revenue requirements, PREPA has requested $10.6 million per year to buy residential meters. This amount does not include maintenance or operating expense. These purchases are part of a replacement plan emphasizing equipment upgrades. PREPA would acquire in FY2017 29,000 meters, an estimated cost of $200/meter plus communication infrastructure. Installing new technology (advanced metering infrastructure—known as AMI or smart meters) adds approximately $198 per meter.[196]

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[193] See also PREPA Schedule F-3 REV.

[194] Fisher-Horowitz Report at 143.

[195] CEPR-JF-02-05 at 19. Commission's Seventh Request of Information (August 12, 2016).

[196] CEPR-AH-02-06 at 8. Commission's Sixth Request of Information (July 29, 2016).

243. As described by Drs. Fisher and Horowitz, smart meters are capable of two-way communication between individual meters and the utility. The two-way communications can provide "interval data" (data that is specific to short periods of time) at a level of frequency (*e.g.*, every 15 minutes) that radial and AMR meters cannot provide. Drs. Fisher and Horowitz questioned the cost-effectiveness of the additional cost of smart meter technology. They recommended that the Commission not approve the extra funds necessary for smart meters; rather, PREPA should install only the current meter models.

244. In 2015, PREPA initiated a pilot program to install 30,000 smart meters in two phases. A July 2015 presentation provided an overview of PREPA's goals (translated):

1. Gather the necessary data to raise the specifications of the optimal system for electric system.

2. Improve the efficiency of the electrical system.

3. Significantly improve the service offered to customers, such as SAIDI, SAIFI, CAIDI and thus reduce the need for management in the commercial offices and Customer Service Center (telephones).

4. Enable automatic remote disconnect and disconnect, to improve service and to allow service cut-off, thus improving cash flow.[197]

PREPA's goals in pursuing smart-grid technology are similar to those of other utilities installing smart grid.

245. Drs. Fisher and Horowitz assert that "[u]tilities have generally found it difficult to justify smart grid technology on a cost effectiveness basis."[198] While PREPA cited Hawaii as an example, Drs. Fisher and Horowitz found this example faulty, because "the deployment cost of $413 million would likely exceed the $345 million in estimated benefits for the project."[199] They also assert that a later PREPA presentation, in July 2016, "clearly indicates that the smart meter program would not be expected to provide cost savings, and is a distraction from PREPA's immediate requirements."[200] They also point out that over half the

[197] Commission's October 20, 2016 Clarification Call Request 161020 No.8 Attachment 1: Slide 3.

[198] Fisher-Horowitz Report at 147.

[199] Hawaiian Electric Companies, Application. Table 2, Page. 8. March 31, 2016. Docket 2016-0087.

[200] Fisher-Horowitz Report at 147.

meters supplied had to be returned for re-calibration, and that the island's mountainous terrain will make cellular communication difficult.[201]

246. The Commission appreciates the efforts by PREPA and our own consultants to assess the benefits and costs of smart meters. We conclude that the efforts already begun, the small amount of dollars at stake, the potential to help consumers manage their consumption, justify this small continuation of an existing pilot program. Therefore, we will approve this funding request.

247. We do, however, share our consultants' concern with spending multiples of this amount in future years without a stronger business case.

d. Directives

(i) ***The Commission approves the full FY2017 distribution system capital budget as requested by PREPA. PREPA shall continue acquiring advanced meter reading ("AMR") meters unless a specific application requires advanced meter infrastructure ("AMI"). If PREPA wishes to acquire smart meters above the 30,000 already acquired without a specific technical application need, it shall submit a detailed business case describing and evaluating the costs and benefits of smart meter deployment. The business case should provide detail of the scope, scale and schedule of deployment, including but not limited to technological and financial issues. It should take into account the need for staff and consumer education for effective meter use.***

(ii) ***PREPA should not commit to any greater expenditure than what is approved here, without approval of the Commission.***

(iv) ***For future purchases of meters, PREPA shall use competitive bidding.***

6. Transportation and Computer Equipment

248. PREPA proposes $19.4 million for vehicles. PREPA maintains a fleet of 3,593 vehicles, of which approximately one-third are SUVs or basic pickup trucks. Another third of the vehicles are either trailers or highly specialized vehicles (such as bulldozers, cats,

[201] *Id.* at 146-47.

trenchers and loaders). The remaining vehicles are either bucket trucks or other line vehicles. Another $3 million is for a replacement helicopter.

249. PREPA also proposes $13.1 million for computer equipment, data management systems and new network equipment. The most substantial request is a data center migration to PREPANetwork, costing $8 million ($6.3 million in FY2017). Using an affiliate (PREPANetwork) for the data center raises the concerns we discuss in Part Five-II. PREPA should have used competitive bidding to select the best provider. Given the immediate need to improve data collection, analysis and reporting, we will not delay this transaction. But future affiliate transactions must adhere to the principles discussed in Part Five-IV.

250. Given the small size of this area and our obvious focus on the larger questions of generation, transmission and distribution, and given that no red flags were raised by our consultants or the intervenors, we approve the full FY2017 transportation and computer equipment budget.

7. Overall findings on capital expenditures in the revenue requirement

251. PREPA shall include $153.462 million for capital expenditure in PREPA's revenue requirement. This is a reduction of approximately $183.096 million from PREPA's request of $336.558 million. Most of this reduction consists of reclassifications rather than actual reductions. Specifically, the $183.096 million reduction reflects the following (as explained in Attachment 3, page 2:

—$125.756 million is an adjustment for the amount of capital expenditure recognized in the debt service coverage ratio.

—$41.340 million reflects the required reduction in spending for AOGP.

—$16 million reflects reclassification of capital expenditures at Cambalache and San Juan to operations and maintenance expense.[202]

D. CILT and subsidies

252. PREPA has proposed specific amounts for the contribution in lieu of taxes ("CILT") and various other subsidies. Most of these items are required by statute. For most of these items, PREPA's proposed amounts are predictions, although some are fixed. In most situations, our statutes do not give us discretion to judge the reasonableness of these amounts. Furthermore, any variation between the predicted and actual amount will be

[202] Another way to understand the $153.462 million is to take the original capital expenditure figure proposed by our consultants, shown on Smith-Day Ex.3 l. 23 as $148.662 million, and add back the $4.8 million for smart meters that our consultants had removed.

reconciled either in a specific rider (discussed in Part Three-III below) or in the one-year budget examinations (discussed in Part Four-III(A) below). Consequently, the Commission approves each amount proposed by PREPA. As set forth on Attachment 1, those amounts are:

—CILT: $51.784 million

—Public lighting: $93.241 million

—All remaining subsidies: $37.901 million[203]

The Commission here offers brief comments on two of these items. Remaining comments about their appropriate treatment appear in Part Three-IV.

CILT

253. PREPA has proposed CILT amount of $51.784 million. PREPA claims that this amount reflects $20 million in CILT savings, reflecting among other things PREPA's collections from for-profit businesses conducted by municipalities, as well as charges to municipalities for electricity consumption above the statutory cap (below which municipalities are not charged for consumption).

254. Historically, PREPA has recovered the CILT through a 0.89 factor in the denominator of its Fuel and Purchased Power Adjustors. The Legislature has prohibited this approach. Consequently, PREPA proposes to recover this amount through a separate "rider." This item is reflected in Attachment 1 at line 14.

Directive

PREPA shall provide to the Commission a report describing its efforts to bill and collect from municipalities in regard to the consumption of electricity at for-profit businesses affiliated with such municipalities.

Irrigation District

255. The "Irrigation District" is a division within PREPA that sells water. It consists of (1) the Guayama and Juana Díaz Irrigation Districts, in the south (PREPA refers to these as "SOUCO" and has grouped them together in its calculation of the subsidy); (2) the Valle de Lajas Irrigation District, in the southwest; and (3) the Isabela Irrigation District, in northwestern Puerto Rico. According to PREPA, 48% of the water produced by the Irrigation

[203] This number reflects the elimination of $37.041 million due to the double-counting discussed in Part Two-I above and $129,000 for reclassification of the Direct Debit Credit as an Operating Expense, as discussed in Part Three-IV. *See* also Attachment 2 and Attachment 3, page 10.

District is used to serve bona fide agriculture clients, whereas 50% is sold to PRASA. The remaining 2% is sold to commercial and industrial clients.

256. The rates for the agriculture clients are set by law.[204] For non-agriculture clients, the Irrigation District sets its rates by, in the words of PREPA's Mr. Rivera, PREPA's Superintendent of Planning and Research, "negotiating" with its customers. When the Irrigation District's water rates fail to cover its costs, PREPA makes up the difference by raising rates to its electric customers—customers who are excluded from the negotiations.[205] This difference is known as the Irrigation District Subsidy. PREPA projects a FY2017 subsidy of $4.152 million.

257. The arrangement is inefficient and illogical. It is inefficient because non-agricultural water rates should cover their costs, unless a reduction from cost is necessary to ensure that the customer will remain "on the system" to contribute something to fixed costs—a concept we will discuss in the context of the load retention discount at Part Three-II(C)(4). Any departure from cost should be reviewed by the Commission to ensure it is no greater than necessary to retain the customer. It is illogical when two parties "negotiate" a discount whose cost is borne by customers excluded from the negotiations, when this happens the fiscal discipline that normally accompanies negotiations is missing.

258. While the Commission has no choice but to approve the FY2017 subsidy, it will not approve this amount in the future, unless PREPA demonstrates (before the negotiations are complete) that the discount is no greater than necessary and that ICPO and at least one prominent commercial or industrial customer have participated in the negotiations and received all relevant information.

259. Contrary to PRASA's suggestion, the Commission is not asserting jurisdiction over the water sales from PREPA to PRASA. Nor is the Commission affecting the terms of any existing water contracts or intervening in the negotiations over water rates. The Commission is asserting its jurisdiction over PREPA's revenue requirement. PREPA's revenue requirement—and thus the charges electricity customers must pay—are affected by the Irrigation District's deficit. Therefore, the Commission has not only discretion but a duty to ensure that such deficit is reduced to the minimum allowed by the statute. Exercising such jurisdiction over the electricity rates does not amount to exercising jurisdiction over water rates, because it leaves PREPA with the choice of how to eliminate the deficit—

[204] *See* Public Irrigation Act of September 18, 1908, as amended and supplemented by Act 63 of June 19, 1919 and Act 2 of May 31, 1950; 22 L.P.R.A. § 251 et. seq., 22 L.P.R.A. § 301 et. seq. and 22 L.P.R.A. § 341 et. seq., respectively.

[205] Although Section 24 of Act 83 of May 2, 1941, as amended, states that the Commonwealth of Puerto Rico will reimburse PREPA for the costs associated to the Irrigation District, several PREPA officials stated during the Technical Hearing that the Commonwealth has not made any reimbursement payments in years.

reducing its own costs, raising its water rates or transferring its Irrigation District operations to others who can operate them without a deficit. All the Commission is doing is setting electricity rates appropriately.

260. Finally, PRASA's proposal to transfer the Irrigation District to PRASA is outside this Commission's authority.

E. Finance costs

1. Amount of debt service in the revenue requirement

261. PREPA projects debt service of $314 million, consisting of $172 million in principal payments and $143 million in interest payments. This amount is reflected in Attachment 1 at line 19.

262. PREPA's debt falls into two main categories: (1) debt that, on completion of the current negotiations, will be collected by PREPARC through the Transition Charge (known as "Participating Debt"); and (2) all other debt (known as "Legacy Debt"). In this rate case, the Commission has no jurisdiction to address the Participating Debt. We deal here only with the Legacy Debt.[206]

263. A recent report published by the Puerto Rico Commission for the Comprehensive Audit of the Public Credit[207] raises important questions about the reasonableness of certain PREPA debt issuances. However, because PREPA's contractual obligation to pay the interest and principal due on that debt remains, Section 6.25(b) of Act 57-2014 leaves the Commission no choice.[208] With respect to the Legacy Debt, PREPA's revenue requirement for FY2017 must include all principal and interest payments due in FY2017.

[206] To emphasize the terminology: Some observers have used the term "legacy debt" to refer to all current PREPA debt. That is not an accurate use of the term. We use the term "legacy debt" to refer only to the debt that must be reflected in the portion of PREPA's revenue requirement over which the Commission has jurisdiction. Debt that becomes "participating debt" will be recovered through the Transition Charge collected by PREPARC. While that amount is part of the *total* PREPA revenue requirement, it is not part of the revenue requirement that is subject to our jurisdiction and that is at issue in this proceeding.

[207] *Pre-audit Survey Report of the Puerto Rico Commission for the Comprehensive Audit of the Public Credit*, September 28, 2016.

[208] "The Commission shall approve a rate that: (i) is sufficient to guarantee payment of principal, interest, reserves, and all other requirements of bonds and other financial obligations that have not been defeased as part of the securitization provided in Chapter IV of the Electric Power Authority Revitalization Act, and reasonable costs of providing the services of the Authority ...."

264. To determine the appropriate amount of debt service costs to include in PREPA's FY2017 revenue requirement, PREPA had to make certain assumptions about which bondholders would become Participating Bondholders and which would remain holders of Legacy Debt. PREPA assumed that $700 million of the uninsured bonds would remain as Legacy Debt. This amount is the maximum amount allowed by the Restructuring Support Agreement, as it exists today. PREPA then apportioned that $700 million according to the percentages of the types of debt existing at PREPA prior to the restructuring.[209] The total amount produces a revenue requirement of $314,319,000. Commission Consultant Hill determined that the method by which PREPA made this estimate was reasonable. The Commission accepts it—recognizing that the number is certain to change when the restructuring negotiations are complete. Any divergence of the final number from this estimated number will be addressed in one of the proceedings discussed in Part Four.

265. The discussion of how debt service will affect the revenue requirement does not end here. The final debt costs to PREPA's ratepayers will depend on the application of the Puerto Rico Oversight, Management, and Economic Stability Act ("PROMESA"). Under Section 601 of PROMESA, if a certain percentage of bondholders elects to participate in a debt restructuring, the PROMESA Oversight Board can require the remaining bondholders to participate as well. If that result occurs, the debt now considered Legacy Debt (*i.e.*, the debt associated with the $314 million in debt service) would move out of PREPA's FY2017 revenue requirement and into PREPARC revenue requirement, to be recovered through the Transition Charge. Ratepayers would save money because all the debt, rather than only the Participating Debt, would be subject to the 85% recovery cap, the lower interest rate and the five-year principal holiday called for by the RSA. And to the extent the PROMESA process causes existing Participating Bondholders to accept additional limits on their recovery, ratepayers will also be better off.

266. For these reasons, the Commission orders PREPA to take all actions possible to use the PROMESA process for the advantage of PREPA customers. If and when these changes occur, PREPA shall inform the Commission of the necessary changes to the revenue requirement. On receiving that information, the Commission will determine how and when to adjust the revenue requirement.

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[209] See PREPA's response to CEPR-SGH-03-05. For more detail, see the revenue requirements testimony of witnesses Pampush, Porter and Stathos (at 17), along with Schedule F-4-Section IX. There PREPA explains that an estimated $1,595 million of debt is assumed to remain outstanding at PREPA. This amount includes $696 million and $35 million in debt held by the fuel lines and Government Development Bank Letter of Credit, respectively, as well as (i) $700 million of uninsured bonds (the maximum allowed the RSA), and (ii) $164 million of Syncora bonds following the debt service payment of July 1, 2016.

2. Debt service coverage ratio

267. Attachment 1 calculates the debt service coverage by multiplying the $314 million of FY2017 principal and interest by a debt service coverage ratio of 1.40. That amount, $126 million, is reflected in Attachment 1 at line 21.[210]

268. A debt service coverage ratio ("DSCR") is the ratio of the cash flow available to meet or cover the debt service payments (interest and principal) to the amount of those payments for a particular time period. Suppose a utility's required principal and interest payments in the current fiscal year total $100 million. Suppose further that rates are established such that if the utility sells the amount of electricity projected and its expenditures are the amount expected, its available cash flow will be $120 million. We would say that the utility's actual DSCR is 1.20.

269. Mr. Hill explained that bondholders typically require a DSCR greater than 1.0 because the revenue and expense levels used to compute rates are only estimates. The real world—hurricanes, power plant failures, fuel price increases and economic slowdown—inevitably intervene, causing outcomes to vary from projections. Despite these variances, bondholders still need to be paid. An ample DSCR reduces the risk that the utility will lack sufficient cash flow to pay all of its obligations, including the obligation to its bondholders. That lower risk translates into lower interest rates.[211]

270. There is no "right" DSCR level; rather there is a need to balance the support necessary for a financially healthy utility against the cost to ratepayers.

271. The 1974 Trust Indenture, under which PREPA issues its revenue bonds (bonds in which the borrower's obligation to repay is secured by its revenues), requires a DSCR of 1.20. Part Two-II(B) explained that PREPA's poor financial condition has shut it out of the capital market. Given the need to improve PREPA's financial condition and to begin increasing bondholder confidence, Mr. Hill recommended a DSCR of 1.40 rather than the 1.20 required by the 1974 Trust Agreement. Drawing special attention to PREPA's $2 billion negative net position, he stated:

> [W]hen the investment community loses confidence in the ability of an entity to pay its debts, it is difficult to win back that confidence. Providing only the minimum amount of Debt Service Coverage required by the bond indenture is

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[210] *See* also Attachment 3, page 1.

[211] Mr. Hill noted that according to the American Public Power Association's *Financial and Operating Ratios of Public Power Utilities* (November 2015), the median debt service coverage ratio for long-term debt service for the public power industry is 2.32. For the publicly-owned utilities with more than 100,000 customers, the median DSCR is 1.85.

not sufficient to signal the investment community that PREPA intends to re-establish its financial position as a reliable lender.[212]

He described the 1.40 DSCR as sufficient to enable PREPA's return to a BBB (investment-grade) rating.

272. Mr. Hill's approach contrasts with that of PREPA's witnesses, who recommended a more expensive 1.57-2.00 DSCR to reach a AA rating. According to Mr. Hill, if the debt service is $314 million, every one-tenth added to the ratemaking DSCR increases ratepayers' cost by $31.4 million. He asserted that PREPA's advisors, by attempting to move PREPA from a C or D rating to A or AA, were not sufficiently considering the effect on ratepayers. At the technical hearing, Mr. Hill used a spreadsheet[213] to show that the PREPA witnesses' proposal would cost the ratepayers more in debt coverage than they would save in interest rate reductions, by a large amount. Given the current low capital costs, this negative benefit-cost ratio was likely to persist. Mr. Hill reasoned that his "more moderate DSCR would improve PREPA's financial position and would also be cost-effective for PREPA's ratepayers while returning PREPA to investment-grade status." He also emphasized that the credit improvement offered by his proposed 1.40 DSCR will be enhanced by the use of the rate procedures described by PREPA Witness Hemphill and Commission consultant Tim Woolf.[214]

273. We agree with Mr. Hill's view that a DSCR of 1.40, well above the minimum 1.20 required by the 1974 Trust Indenture, will signal to the investment community the Commission's support for PREPA's efforts to improve its financial position.

274. Finally, at the technical hearing Mr. Hill and the PREPA witnesses agreed that as long as the revenue requirement includes capital expenditures in current rates (a provision the Commission approved in Part Two-III(C)(7)), there is little practical difference between a 1.40 coverage ratio and a 1.57-2.00 coverage ratio, because the amount of capital expenditure included in the revenue requirement exceeds the amount associated with either coverage level. At such time that including capital expenditures in rates is no longer necessary, however, Mr. Hill's 1.40 DSCR would mean substantial ratepayer savings relative to PREPA's proposed 1.57-2.00.

3. The prospect of renegotiating debt service

275. Some intervenor witnesses argued that PREPA's debt is too high and should be renegotiated downward. These arguments do not have practical value, for two reasons.

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[212] Hill Report at 22.

[213] Commission's Technical Hearing Exhibit 3.

[214] In Part Four, the Commission addresses the Hemphill and Woolf proposals and adopts various budget examination procedures.

276. First, as we detailed in our June 2016 Restructuring Order, PREPA has already obtained from bondholders a 15% reduction in principal, lower interest rates ~~and a five-year~~ deferral of principal. No intervenor presented evidence that PREPA could have obtained more concessions had it bargained more effectively. No intervenor presented evidence that the relationship between PREPA and its bondholders was other than arm's-length. PREPA's lead negotiator was Alix Partners. Ms. Donahue, PREPA's Chief Restructuring Officer, testified at the Technical Hearing that while the bondholders required PREPA to hire a restructuring team, the decision about whom to hire was PREPA's. Alix Partners had to compete against three other companies for the job. No intervenor lawyer cross-examined Ms. Donahue on this point. In a political setting, it may be acceptable to complain about costs. In an administrative adjudication, arguments require evidence. On the question of whether PREPA could have negotiated a better arrangement, intervenors offered no evidence.

277. Second, arguments must be guided by law. While the Commission has authority to approve future debt, it has no authority to adjust the outcome of the PREPA-bondholder negotiations. In administrative litigation, it is the responsibility of attorneys to ensure that expert testimony remains within the legal boundaries that bind the forum. In this instance, some intervenor attorneys failed to heed this responsibility. The Commission expects that this type of professional error will not be repeated.

4. Future bond issuances

278. No longer can PREPA use debt as a means of avoiding rate increases. Debt is appropriate, however, for long-term investments whose value justifies their costs. Oversight of future bond issuances must address their purposes, cost and timing, as well as PREPA's ability to repay. That oversight must be performed by PREPA's Board, the Consulting Engineer and, of course, this Commission. To that end, Section 6(o) of Act 83 provides:

> Except for the bonds and other financing instruments related to the Authority's restructuring pursuant to the agreements entered into with the creditors of the Authority, whose debt parameters shall be governed by the provisions of Chapter IV of the Electric Power Authority Revitalization Act and the Creditors' Agreement, before borrowing any money or issuing bonds for any of its corporate purposes, the Authority shall require the Commission's approval showing that the proposed financing shall be used to fund projects and defray the costs associated therewith in accordance with the Integrated Resource Plan and the Energy RELIEF Plan.

Section 6.3(n) of Act 57-2014 further provides that PREPA shall seek "written approval of the Energy Commission prior to the issue of any public debt." This type of regulatory review of utility debt issuances is common among mainland U.S. regulatory commissions. Also typical is a requirement that the utility submit, along with its request for approval, the following types of information, as all recommended by Mr. Hill:

(1) a prospectus for the debt issue (the document published for investor review of the debt offering); (2) a copy of the supporting Trust Indenture if it is different from the 1974 Trust Indenture under which all of PREPA's revenue bonds currently are issued; (3) a description of any special considerations associated with the new debt issue; (4) if not otherwise provided, a description of the expected yield, the term of the debt, a schedule of payments, and a comparison to current yields of similarly-rated bonds; and (5) five-year financial projections showing that the Company will be able to meet its indenture-mandated debt coverage ratio following the issuance of the new bonds.

The Commission anticipates issuing a rule establishing these requirements, well in advance of PREPA's regaining access to the capital markets.

5. Directives

a. ***PREPA shall include in its FY2017 revenue requirement $314 million for debt service principal and interest.***

b. ***PREPA shall include a debt service coverage amount of approximately $126 million, reflecting a debt service coverage ratio of 1.40 applied to the $314 million in debt service.***

c. ***PREPA shall inform the Commission monthly on its progress regarding financial restructuring, including its efforts to obtain an investment grade credit rating for the new debt to be issued by PREPARC, and its meetings with members of the PROMESA Oversight Board. PREPA shall submit to the Commission copies of any formal presentations that it (or PREPARC) makes to credit rating agencies or to the PROMESA Oversight Board.***

d. ***PREPA shall use all reasonable efforts to persuade the PROMESA Oversight Board to provide the maximum debt service relief available, including demonstrating to that Board how the savings will benefit the Commonwealth's economy and its electricity consumers.***

F. Income from sources other than electricity sales

279. PREPA proposes for its FY2017 revenue requirement Other Income of $38.925 million. This amount reflects income from sources other than charges for electric service. Examples of Other Income include: non-operating rental income, sinking fund interest income, and other miscellaneous income. This amount reduces the revenues needed to provide electric service. It is reflected in Attachment 1 at line 28.

Directives

1. ***PREPA shall reflect a FY2017 amount of $38.925 million in Other Income.***

2. ***In future years, PREPA shall detail the basis for amounts included as Other Income.***

IV. Calculation of required revenue increase

A. Calculation of revenue requirement

280. The Commission adopts an adjusted base rate revenue requirement (excluding Transition Charge) of $3,413,904,000.[215]

281. To compute the additional revenue required to cover PREPA's needs, we must subtract the revenue it would receive under its current rates, assuming a forecasted level of sales, from the $3.414 billion base rate revenue requirement adopted by the Commission. The difference is called the "deficiency": the amount by which revenues must be increased by increasing rates.[216] As shown on Attachment 1, lines 30 and 31 (Column A), PREPA expects current rates to produce $1.658 billion in fuel and purchased power revenue and $1.078 billion in base rate revenue at current rates, for a total of $2.737 billion (the $2.776 billion on Attachment 1, line 32 Column A is the sum of that $2.737 billion plus the "Other Income" of $38.9 million). We then increased that amount by the $461.3 million in additional fuel costs projected by Drs. Fisher and Horowitz, to produce a revenue requirement (not counting the amounts covered by the Transition Charge) of $3.237 billion.[217]

[215] See Attachment 1, l. 26, Column C. To the original consultant-proposed figure of $3,406,557,000 (Smith and Dady Ex. 3), we added back the $4,800,000 relating to smart meters (see also Attachment 3, page 2), the $624,000 related to stipulated fines and penalties that bad been included in Smith and Dady Ex. 3 based on a miscommunication with PREPA (see also Attachment 3, page 7), the $1,711,000 adjustment relating to reconnection fees (see also Attachment 3, page 9) and reflected a revised amount for Bad Debt Expense resulting from the impact of these other adjustments (see also Attachment 3, page 8). PREPA argued that there was a $643,000 error in the CILT and Subsidy pass through line item. The Commission was not able to verify this, therefore has rejected this adjustment. The Commission has reconciled the CILT and Subsidies amounts as shown on Attachment 4. Such amounts, as adjusted by the Commission, reconcile to the amount reflected in the revenue requirement without any need for PREPA's requested correction.

[216] We discuss the sales forecast in Part Two-IV.B.

[217] See Attachment 1 at ll. 29-32.

282. Comparing this $3.237 billion in current revenues (Attachment 1, line 32) with the Commission-approved revenue of $3.414 billon (Attachment 1, line 26) indicates a revenue deficiency of $177.0 million (as shown on Attachment 1, line 34). That revenue deficiency of $177.0 million is approximately $45.256 million less than PREPA's claimed revenue deficiency of $222.256 million.

283. When the Commission established provisional rates on June 24, 2016, it used PREPA's full proposed revenue requirement (thus raising rates to eliminate an annualized $222.256 million deficiency). Since the deficiency is only $177.0 million, the Commission must return to ratepayers the excess amounts collected from them. We address that subject in Part Two-V. The Commission also needs to determine how to adjust specific rates under specific tariffs produce the new revenue requirement. We address that subject in Part Three-II.

284. Having determined the deficiency in dollars, we now need to determine the increase in existing rates (excluding the Provisional Rate) necessary to eliminate that deficiency. To do so, we need to divide the deficiency by the expected sales (in kWh) to arrive at the necessary cents/kWh increase. We thus turn to the question of sales next.[218]

B. Forecasts of sales and load

1. The significance of sales and load forecasts

285. To satisfy its obligation to serve their customers' needs, a utility must accurately predict those needs. Then customers must pay rates calculated to produce the revenue necessary to serve those needs. Rates result from dividing the revenue requirement by the expected sales. Revenues (in $) divided by sales (in kWh) gives us a rate ($/kWh). Since we have determined the revenue requirement we now must forecast sales.

[218] Rejecting the proposed revenue requirement, as ICSE-PR recommends, would cause a shortfall of $177,000,000 in PREPA's revenues—at a time when PREPA needs much more, as detailed by Drs. Fisher and Horowitz. It would leave PREPA unable to pay its bondholders, thereby weakening the agreement under which the bondholders have pledged not to declare default and sue PREPA for nonpayment. It would signal that this Commission fails to appreciate two realities: that without outside capital PREPA cannot rebuild its system, and that outside capital will not invest in PREPA without confidence that the Commission understands PREPA's financial needs. Our chosen path is careful and gradual: grant revenue increases only on a showing of need, require budgets to ensure appropriate spending of the revenues, investigate performance deeply to cause the necessary change in cultures, establish infrastructure priorities through the IRP process and require revenue requests to reflect the approved IRP, and heed the statutory requirement that rates must produce revenues sufficient to cover the principal and interest owed on outstanding deht. ICSE-PR's position heeds none of these requirements.

286. Utilities typically forecast two distinct things: total sales of electricity (in kilowatt-hours or megawatt-hours), and "peak load" (in megawatts).[219] The sales forecast expresses how much total energy the utility expects to sell over the course of a year. The peak load forecast states the maximum power the utility expects to need to serve all customers at any one time during that year.

287. The sales forecast is the denominator in various fractions used to set rates. Sales tells us the number of units over which a particular cost must be recovered. Where a utility collects its revenue requirement through sales of kWhs, the numerator is the revenue requirement (in $), while the denominator is sales (in kWhs), giving us a rate in $/kWh. When the utility collects its fuel costs through a fuel clause, again the fuel costs are in the numerator (in $) and the sales are in the denominator (in kWh). Predicting sales accurately is crucial to setting rates correctly.

288. An accurate sales forecast is also necessary for utility budgeting. Expectations of total spending on fuel, purchased power, and operations and maintenance all depend on expectations of sales, because increased sales lead to increased costs in in each of those categories.

289. Like other utilities, PREPA uses forecasted sales as an input into PROMOD, the production cost model described in Part Two-III.B above. To calculate the total amount of energy it needs to generate every year, PREPA needs a sales forecast. This information, along with other data such as fuel cost, operating cost and data on generation performance (such as how quickly specific units can ramp up and ramp down) are input into PROMOD. PROMOD then determines an optimal dispatch pattern for the utility generation fleet for a given period. PROMOD also predicts the costs (as well as expected fuel consumption, emissions, and other system behavior) associated with that dispatch pattern. Different sales forecasts lead to different dispatch patterns with different associated costs.

290. Both sales (kWh) and peak (MW) forecasts can thus affect utilities' planning for a variety of periods—days, weeks, months, years and decades. Peak load forecasts are the key input to determinations of resource adequacy. Local or system-wide increases in peak demand can cause the need to install new generation and transmission facilities. Peak forecasts also shape cost of service studies, which affect allocation or revenue responsibility (as discussed in Part Three-I).

2. Acceptance of the forecast for FY2017

291. The Fisher-Horowitz Report (at Part IV) presented an extended critique of PREPA's approach to sales forecasting. The critique questioned the support (in terms of model design and data) for PREPA's forecasts, the accuracies of past predictions, the

[219] Peak load, sometimes called peak demand refers to the maximum amount of power that a utility must supply, to keep the lights on, at any one moment of a year.

treatment of energy efficiency, the calculation and use of elasticity of demand, and discrepancies between sales predictions and numbers actually used in the revenue requirements model. At the technical hearing, Dr. Horowitz and PREPA personnel had an extensive and deep debate over their contrasting positions.

292. The one agreement was that PREPA's forecast for FY2017 was acceptable. For purposes of this case, therefore, the Commission will accept it. The Fisher-Horowitz Report points that when PREPA forecasts one year ahead or one month ahead, the difference between prediction and actual is small, and comparable to the difference experienced by other utilities. Moreover, the extent PREPA's revenues are affected by incorrect short-term forecasts, corrections can be made in the adjustor clauses and the one-year budget examinations or the three-year rate proceeding.[220] The disagreements concern forecasts over longer periods.

293. With so many immediate issues to address in the short time allowed for this proceeding, it is not possible to resolve the many differences that have arisen over forecast methodology. The dialogue at the technical hearing made clear that PREPA and the Commission will benefit from a deeper exploration. From that deeper exploration, the Commission can establish guidelines for future forecasts. The result will be fewer disagreements and over and greater confidence in PREPA's forecasts. The Commission will address this topic within the next few months.

3. Directives

294. We will adopt the following recommendations from the Fisher-Horowitz Report, but will schedule a technical discussion to give them more precise shape:

a. ***PREPA shall develop a single, reliable, theoretically sound forecasting model for each rate class. Each model should be able to predict adequately historical sales.***

b. ***PREPA shall develop a new sales forecast based on these models prior to submitting to the Commission another planning or rate case.***

c. ***Any changes to PREPA's forecasting models in the future shall be clearly documented and supported by evidence.***

d. ***In submissions relating to forecasts, PREPA shall provide clear, comprehensive, and accurate methodological documentation, including work-papers showing all relevant***

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[220] We will discuss interim rate proceedings in Part Four.

inputs and calculations, along with note sources for all assumptions and hard-coded values.

e. ***All forecasts shall explicitly account for energy efficiency, demand management and demand elasticity, by class and on a total system basis.***

C. Calculation of rate increase

295. PREPA's projected sales are 17,268,325,180 kWh.[221] Therefore, the average rate increase corresponding to the revenue requirement deficiency of $177,000,000 is approximately 1.025 ¢/kWh. The average rate increase will be applied to the energy charge component of the base rate for all PREPA clients, except as described in Part Three-II.

296. Given the many directives and decisions made by the Commission in this Final Resolution and Order, PREPA shall calculate the actual rate increase for each tariff code and provide such information for Commission review and approval no later than February 15, 2017.

Directives

a. ***As part of its compliance filing, PREPA shall submit no later than February 15, 2017 for Commission review and approval, the computation and description of the actual permanent rate increase for each tariff code and the language it will include in each customer's bill explaining the increase.***

b. ***As provided in Section 6A(f) of Act 83, PREPA's permanent rates shall enter into effect 60 days from the date of approval of this Final Resolution and Order.***

V. Reconciliation of the new permanent rate with the provisional rate

A. Commission finding

297. The provisional rates approved by the Commission on June 24, 2016 were based on PREPA's projection of a deficiency of $222.256 million. Since the Commission finds a deficiency of only $177.0 million, the difference of $45.256 million (annualized) must be returned to ratepayers, because the effective date of the new rates was July 27, 2016. How this money is returned to ratepayers is the subject of this subsection (relating to revenue requirement) and Part Three-II (relating to rate design).

[221] PREPA Ex. 3.0 at 39. See also PREPA Ex. 27.00.

298. The Commission's Rate Case Filing Rules at Section 2.02, Request for Provisional Rates, state:

> Pursuant to Article 6.25(e) of Act 57-2014 and Section 6A(f) of Act 83-1941, when issuing a final order establishing permanent rates, the Commission shall order PREPA to adjust its customer's bills in order to credit or collect any difference between (a) the Provisional Rate charged by PREPA during the time period in which such Provisional Rate remained in effect and (b) the permanent rate which the Commission determines should have applied during such time period, so as to ensure that the Provisional Rates were just and reasonable. Such order shall reflect any upward or downward adjustment, effective as of the date the Provisional Rates were established, necessary to ensure the Provisional Rates were just and reasonable.

PREPA has stated that reconciling on an individual customer-by-customer basis would require changes to the customer billing system, costing approximately $130,000 per month. Reconciling on a customer class basis would avoid this nearly $910,000 (seven months times $130,000 per month) cost—a cost which would be borne by ratepayers.

299. The Commission finds that benefits of perfect accuracy in customer refunds are not worth making customers pay this additional $910,000 cost. PREPA shall credit the $45.256 million (annualized) on a customer class basis. The reconciliation will take place starting with the first month the permanent rate will be in effect for the same number of months the provisional rate was in effect. The legal support for this conclusion is discussed next.

B. Legal analysis

300. The Commission must determine whether Section 6A(f) of Act 83 provides specific guidelines and requirements regarding how to adjust customer bills for the difference between provisional rates and permanent rates.

301. Because the Commission approves a Provisional Rate based only on a limited review of information accompanying PREPA's request, that rate will not necessarily be the same as the permanent rate approved after a full evidentiary hearing. The statute therefore requires the Commission to order PREPA to reconcile the difference between the provisional rate and the permanent rate. Reconciling means granting customers a credit to the extent the provisional rate exceeds the permanent rate, or requiring the customers to pay PREPA the difference if the permanent rate exceeds the provisional rate. The question is whether there needs to be a specific reconciliation for each of PREPA's 1.5 million customers or whether the reconciliation can occur for each customer class as a whole.

302. Section 6A(f) of Act 83 states:

> Upon issuing any order after the rate review process, the Commission shall order the Authority to adjust customer's bills to credit or charge any difference

between the temporary rate established by the Commission and the new rate approved as a result of the rate review process. In the event a person ceases to be a customer during the effective term of the temporary rate, the Authority shall be required to issue a refund and shall be entitled to collect any difference between the temporary rate established by the Commission and the new rate approved as a result of the rate review process.[222]

303. While every customer will receive an adjusted bill, the question is whether the adjustment must address each customer's individual experience or whether the adjustment can be made to each customer class as a whole. The first sentence of Section 6A(f) provides that PREPA shall "adjust customers' bills". In this phrase, "customers'" is a plural possessive, signaling to us that we may make the adjustment for the entire class (the Spanish version, "ajustar la factura de sus clientes" also uses customers in the plural; neither the English nor the Spanish version say "each client"). Although it recognizes that such phrase may be interpreted as a reconciliation on a customer-class basis[223], ICPO argues that Section 6A(f) requires permanent rates to be reconciled with provisional rates on a per-customer basis.[224] ICPO's statement is based on a separate provision within Section 6A(f)—a provision requiring PREPA to refund to a sub-category of all customers—those who leave PREPA's system while the Provisional Rate is in effect. That portion of Section 6A(f) does not relate to whether the reconciliation mechanism must be customer-specific or on a customer-class basis. The purpose of the latter portion of Section 6A(f) is two-fold. First, it ensures that the reconciliation will benefit all customers, whether they are existing customers or whether they are former customers who have left the system after the Provisional Rate entered into effect.

304. Secondly, it distinguishes between existing and former customers for purposes of how PREPA would reimburse or collect any difference between the Provisional Rate and the permanent rate. Section 6A(f) specifically requires PREPA to, in the case of over-collecting (when the Provisional Rates is higher than the permanent rates), *credit* that difference to its current customers. In the case of customers who leave the system, Section 6A(f) provides that, in the case of an over-collection, PREPA would issue a *refund* to the customers. A credit entails a downward adjustment on the customer's bill, while a refund

[222] Similar language is found in Section 6.25(e) of Act 57-2014.

[223] See ICPO's Legal Brief at 11, footnote 9. During the Technical Hearing, ICPO agreed with PREPA that the statute was broad and did not establish a specific mechanism for achieving the reconciliation methodology. ICPO further agreed that the statute did not require a customer-specific refund. Also, in response to questions from the Commission Staff, ICPO agreed that in determining the adequate reconciliation mechanism, factors like cost, time and resources should be taken into account to determine the reasonableness of a proposed reconciliation. ICPO further stated that, if customer class reconciliation mechanism (as opposed to a customer-specific mechanism) benefited PREPA's customers, then such a mechanism would be allowed under Act 57-2014.

[224] *Id.* at 11.

requires PREPA to physically disburse a determined amount of funds. The reason for the distinction is simple. An existing customer has a continuing relationship with PREPA, so PREPA may adjust its customer's bills to credit or collect any difference between rates. With a customer who has left the system, there is no continuing relationship, so there would be no subsequent bill for PREPA to adjust. In those cases, the Legislative Assembly provided that PREPA must issue a refund to such customers. Whether the amount to be reimbursed is calculated on a customer-specific or customer-class basis is irrelevant to how that amount is returned to the customer—either through a credit or a refund.

305. Section 6A(f) provides a simple mandate to the Commission: to ensure that each customer class pays the actual costs incurred by PREPA in providing electric services to that class. The phrase "adjust customers' bills" cannot be interpreted to mean that the Legislative Assembly required PREPA to study the seven-month billing history of each of its 1.5 million customers to calculate the exact amount each customer is entitled to receive or required to pay—especially where the difference between the provisional and permanent rates is small—as it is here. The phrase "adjust customers' bills" refers to the ordinary procedure of PREPA including on its customers' bill the necessary adjustments to credit or collect any difference between rates, and not to the specific process through which that amount is calculated. As such, we hold that Section 6A(f) does not require the Commission to approve a customer-specific reconciliation mechanism.

Directives

1. ***The reconciliation of provisional rates with permanent rates shall commence when the permanent rates are in effect.***

2. ***The reconciliation shall occur over the same amount of months that the provisional rates were in effect.***

3. ***The reconciliation shall apply to the broad customer classes identified in Part Three-I.A., rather than on a customer-specific basis. This approach will save the $130,000 per month that PREPA has estimated would be required to reconcile per-customer.***

4. ***Because of the small size of the difference tween the provisional rates and the permanent rates, the reconciliation shall be done by adjusting the per-kWh charge, rather than by adjusting each element of a customer class's rate structure.***

5. ***As part of its compliance filing, PREPA shall provide, no later than February 15, 2017, the following information: (i) the total amount (in dollars) to be credited to customers, (ii) the allocation among customer classes of the total amount to be credited, and (iii) the amount (in cents/kWh) to be credited to each customer class on every billing cycle.***

VI. Required improvements in PREPA's financial reporting and related procedures

306. Our review of PREPA's rate request was hampered by the absence of audited financial statements. The latest audited statements are for FY2014. PREPA informed the Commission that it "believes" we will receive the audited statements for FY2015 in January 2017.

307. The absence of current audited statements has several serious implications. First, PREPA's proposal for a "formula rate mechanism" (discussed in Part Four-II below) assumes availability of audited statements by October of each year. Basing annual updates to the revenue requirement on unaudited information risks basing rates on unreliable cost information. Second, the willingness of existing creditors to show lenience on existing loan terms, and of new creditors to grant new credit on reasonable terms, depends on their trusting PREPA's financial statements.

Directives

1. ***PREPA shall take necessary steps to assure that its audited financial statements can be completed and made available on a timely basis.***

2. ***PREPA shall submit to the Commission its Monthly Reports to the Governing Board. In addition, the report to the Commission will include the following:***

    a. ***explain significant variances between (i) budgeted and actual data, and (ii) current and prior year data.***

    b. ***provide information on Labor Costs, including how current month and year-to-date payroll, pensions, OPEBs and other employee benefit costs compare with prior year amounts and current year budgets.***

    c. ***provide information on PREPA's actual debt service coverage ratio.***

    d. ***provide information on the status of PREPA's financial restructuring, including significant events that have occurred during the reporting month.***

3. ***PREPA shall allocate budgets for new initiatives and costs to specific functional areas, according to standards to be determined by the Commission.***

308. ***Special directive regarding the Consulting Engineer:*** The 1974 Trust Indenture requires that for as long as any bonds issued under that agreement are outstanding, PREPA must retain an independent Consulting Engineer. Section 706 states:

> It shall be the duty of the Consulting Engineers to prepare and file with the Authority and with the Trustee on or before the 1st day of May in each year a report setting forth their recommendations as to any necessary or advisable revisions of rates and charges and such other advices and recommendations as they may deem desirable.[225]

This broad language requires the Consulting Engineer must provide to PREPA and the Trustee opinions on rates, budgets, bond issuances and financial covenants, as well as the state of the utility's infrastructure and the need for improvements.

309. PREPA's Business Plan proposes to amend the 1974 Agreement to phase out of the Consulting Engineer's role.[226] At the evidentiary hearing, Ms. Donahue and Dr. Quintana clarified that the intent was not to eliminate the role, but to redefine it and find a new Consulting Engineer.

310. PREPA and its bondholders should not eliminate the role of Consulting Engineer. They should, however, find a new entity, because the prior firm failed in multiple ways to inform the PREPA Board and the public about the deterioration of PREPA's finances and of its physical system. Despite the failures of the prior Consulting Engineer, the concept of an independent entity providing analysis to PREPA, bondholders, the Commission and the public is sound and essential. The PREPA Board needs an independent, expert voice, one with a professional obligation to examine PREPA from top to bottom, and to be truthful and candid about what it observes, to opine on the state of PREPA's physical infrastructure and to recommend revenue increases when necessary. All the topics and analyses topics covered by the prior Consulting Engineer should be addressed by the new one.[227]

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225 1974 Trust Agreement, § 706.

226 See Ex. 3.02 at 65.

227 The Table of Contents to the 40th Consulting Engineers Report (2013) indicates detailed information provided regarding the following aspects of PREPA's operations: Production Plants, Environment, Co-generators, Transmission and Distribution Systems, Technological Systems, General Facilities, Puerto Rico Economy, Econometric Projections, Generation Forecast, Demand-Side Management and Energy Conservation Programs, Capacity Planning, Alternative Energy Sources, Fuel Mix, Energy Sales Forecasts, Rate Schedules, Subsidies and Credits, Selected Rates, Cost of Service, Annual Budget, Revenues, Expenses, O&M Expenses, Net Revenues, Debt Service Coverage, Depreciation, Accounts Receivable, Contributions to the Commonwealth, Financing, Capital Improvement Program, Retirement Funding, Inventories, Insurance, Funding Recommendations, Human Capital, Legal Affairs, PREPA Subsidiaries.

Directive

As required by the Trust Indenture, PREPA shall retain a Consulting Engineer, different from the one previously engaged. Before recruiting the Consulting Engineer, PREPA shall submit to the Commission a description of the duties and the required qualifications. The Commission may comment on such description, but PREPA shall have full discretion to choose the Consulting Engineer. PREPA shall provide the Commission any information it requires about the functions, activities and reports of the Consulting Engineer.[228]

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[228] In its brief, PREPA "opposes this recommendation being part of this rate review, which involves a Trust Agreement matter, and which is inappropriate based on the record and law and unnecessary here." The Commission is imposing this requirement independent of whether it remains in the Trust Agreement. This requirement is not merely a "Trust Agreement" matter; it is a matter of protecting consumers from excess costs, poor financial and operational decision making, deteriorating infrastructure and the myriad of other problems discussed throughout this order. For PREPA's revenue requirement to be just and reasonable, there must be an independent entity reviewing and reporting on its operations, regularly and transparently. The Commission will not approve a rate increase without assuring itself that the money will be spent wisely. That is the benefit of a Consulting Engineer that does its job properly.

PART THREE:
Revenue Allocation and Rate Design for FY2017

311. As explained in Part Two, the FY2017 revenue requirement represents the total dollars PREPA must receive during FY2017 to pay all its expenses, fund the approved capital expenditures, pay the principal and interest on debt due during the year and have an appropriate debt service coverage ratio. Having determined the revenue requirement, the Commission now needs to set rates, so that PREPA's customers pay the dollars that produce the revenue requirement.

312. Setting the rates involves two major steps: Allocating responsibility for PREPA's revenue requirement among the major customer classes, then designing the rates to be paid by the individual customers within each class. We address those two subjects in Part Three-I (revenue allocation) and Part Three-II (rate design). Part Three-III discusses riders—special mechanisms that recover specific costs outside of base rates. One rider is for "subsidies," the subject we address separately in Part Three-IV. Finally, Part Three-V addresses rate design issues specific to net-metering for customers who own renewable energy facilities.

I. Revenue allocation

A. Classes, tariffs and tariff codes

313. Revenue allocation divides the responsibility for a utility's revenue requirement among the classes of customers. The first step in revenue allocation, therefore, is to divide customers into classes. PREPA, like many utilities, uses the following broad customer classes:

Residential
Commercial
Industrial
Agriculture
Public Lighting
Other Public Authorities (which PREPA sometimes places into the commercial class for presentation purposes).

Within each of these broad classes, customers are assigned to different tariffs, depending on the customers' cost-causing characteristics. PREPA Exhibit 4.0 lists 17 tariffs:

1. GRS (general residential)
2. RH3 (municipal public housing)
3. LRS (low-income residential)
4. RFR (Public Housing Administration tenants)
5. GSS (secondary general service)

6. GSP (primary general service)
7. TOU-P (time-of-use primary)
8. GST (transmission general service)
9. LIS (large industrial)
10. TOU-T (time-of-use transmission)
11. SBS (standby service)
12. GAS (general agriculture service)
13. PPBB (independent power producer)
14. PLG (public lighting)
15. USSL (some unmetered loads)[229]
16. CATV (cable operator equipment)
17. LP-13 (sports-field lighting)

Most of these tariffs serve only one customer class. The tariffs GSS, GSP, GST and TOU-P all serve customers in multiple classes: commercial, industrial and/or public classes.

314. PREPA (like many utilities) then divides most tariffs into several "tariff codes," reflecting such distinctions as:

1. the size (measured in various ways) of customers on the RH3, RFR, LRS, TOU and LIS tariffs.

2. whether GRS customers are subject to the discount for students, the handicapped and the elderly.

3. whether the GSS, GSP, GST and TOU-P customers are commercial, industrial and/or public authorities.

4. whether the customer uses net metering or storage air conditioning.

5. whether the customer takes standby service, or has a rate discount for new or expanded loads.

6. the end-uses served by public lighting and unmetered loads.

PREPA lists 71 tariff codes, of which 47 have customers. (Schedule G-1, tab Input-1) Overall, then, PREPA has five or six classes, 17 tariffs, and 47 active tariff codes.

229 Other unmetered loads, mostly for light, are sometimes treated as part of public lighting as sometimes as separate tariffs.

B. PREPA's cost-of-service study

1. Purpose and organization of a cost-of-service study

315. A central principle of just and reasonable ratemaking, economic efficiency and equity is that costs should be borne by those who cause them. Once a commission determines customer classes, tariffs and tariff codes, the next step is to determine how customers in those various categories cause the utility to incur costs. The starting point for determining cost causation is a cost-of-service-study ("COSS").[230]

316. In determining cost causation, analysts consider the following factors, among others:

1. each class's contribution to the current need for the equipment and services;

2. each class's contribution to the current usage of the equipment or of the services that require the expenditure;

3. each class's contribution to the rationale for undertaking a cost; and

4. how much each class currently uses the service that created a cost in the past.

Using accounting data, load data and other inputs, a COSS estimates cost responsibility by following three steps: functionalization, classification and factor allocation.

1. ***Functionalization*** places each cost within one of the following areas: generation, transmission, distribution, customer service or overhead (this last sometimes called "administrative and general"). These general functions can be subdivided into sub-functions and accounts.

2. ***Classification*** focuses on the forces that drive the utility's need to incur costs. For the costs associated with each function, sub-function or account, classification determines whether those costs are driven by one or more of three categories of factors: demand, energy and the number of customers. Fuel, for example, is classified as energy-related because the need for fuel is driven by the consumption of energy. Generation and transmission are classified as demand-related when these facilities are built for purposes of serving demand (*i.e.*, the combination of all customers' need for power at a

[230] A cost of service study is often called an "embedded cost of service study" because it is based on costs incurred in the past (embedded costs), which costs are necessary to provide service in the present. A generating plant provides service today but its costs were incurred in the past. An embedded cost study thus differs from a marginal cost study, which focuses on costs to be incurred in the future. We will discuss marginal costs in Part Three-II.A below.